PUBLIC UTILITIES BOARD, ALBERTA

ANNUAL REPORT 1991

Public Utilities Board
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March 30, 1992

The Honourable D.R. Getty
President of the Executive Council of Alberta
Legislature Building
Edmonton, Alberta

1991 ANNUAL REPORT

Dear Sir:

We have the honour to submit herewith the Annual Report of the Public Utilities Board for 1991.

In addition to providing the information which is required by statute, this Report provides a brief description of the Board and its responsibilities and highlights significant activities and developments which occurred during 1991.

Yours respectfully,

A.C. Barfett - Acting Chairman

T.D. Hetherington - Member

J.R. Dunstan - Member

N.W. MacDonald - Member

B.T. McManus - Member

R.D.S. Ward - Member

T.C. Roberts - Member

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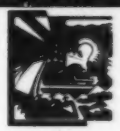
THE BOARD'S ROLE



The main purpose of the Public Utilities Board is to establish just and reasonable rates for utility services. The need for regulation arises because utilities generally provide necessary services on a monopoly basis. In light of the large investment required in plant to provide utility service, it is not economically viable for more than one utility company to supply service within a given franchise area. This absence of competition for the services provided by utility companies resulted in the establishment in 1915 of an independent tribunal to ensure that utility rates were set at a level that was fair to both the customers and the investors in the utility.

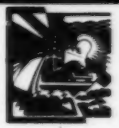
The Board's prime responsibility remains to balance the interests of the consuming public and the utility companies. It must permit the utility the opportunity to earn sufficient revenues through customer rates to recover its costs of providing the service which includes a fair return on its investment in utility property and plant, while ensuring that these rates are just and reasonable and that the quality of service is safe and adequate.

It should be noted that there are different levels of regulation. The Board has the jurisdiction to establish rates and terms and conditions of service for public and gas utilities, as defined in the statutes. However, the Board has only limited jurisdiction respecting municipally-owned utilities and natural gas co-operatives. The Board's authority with respect to these non investor owned utilities is restricted to hearing certain specific consumer complaints with respect to their rates. Furthermore, the Board has no regulatory authority with respect to the two telecommunications utilities which operate within the province.

A listing of all utilities which fell under the full jurisdiction of the Board as of December 31, 1991 is contained in Appendix 4.

The Public Utilities Board is a tribunal with quasi-judicial powers. In dealing with the matters which the Legislature has assigned to it, the Board has been granted the same status as the Alberta Court of Queen's Bench.

Although the Board has been granted the authority to establish its own procedures, there are certain restrictions on its conduct. For example, the Board is subject to the Administrative Procedures Act, which requires, among other things, that the Board give adequate notice to all affected parties; that all parties who may be adversely affected by an application before the Board be afforded an opportunity to furnish relevant evidence and to present argument; and that the Board give written reasons for its decisions.



The decisions of the Board may also be reviewed or appealed. Pursuant to Section 62 of the Public Utilities Board Act, an application for leave to appeal a decision or order of the Board may be made to the Alberta Court of Appeal, and subsequently to the Supreme Court of Canada, on questions of jurisdiction or law, but not on findings of fact.

In respect of its quasi-judicial duties the Board derives its mandate from numerous statutes, and from Orders in Council issued pursuant to the statutes. While the Board operates pursuant to more than thirty different statutes, its authority is primarily contained in the Public Utilities Board Act and the Gas Utilities Act. These statutes provide the Board with a framework which guides the Board in setting rates for those utilities under its full jurisdiction. Like most other regulatory agencies in North America, the Board employs a rate base - rate of return methodology in establishing rates.

Firstly, the Board is required to set a rate base for the utility. This involves a determination of the amount of money net of depreciation the utility company has invested over the years in its facilities which are required to provide service to the public within Alberta. The Board must then establish a fair return on this rate base, which is essentially equivalent to the annual cost of the capital invested in that rate base. The utility company's reasonable operating expenses as approved by the Board are added together with the fair return to establish the utility's revenue requirement. This represents the amount of money the company will need to have an opportunity to collect from utility sales in order to pay expenses and earn its fair return. Finally, the Board must determine how the revenue requirement should be allocated among the different types or classes of customers - residential, commercial and industrial. While the statutes do not provide the Board with much guidance respecting rate design, they do specify that rates may not be unjustly discriminatory nor unduly preferential. As part of the general rate application process, the Board also reviews the utility's terms and conditions of service, to ensure that fair and reliable service will be provided to customers.

This ratemaking process occupies the majority of the Board's time. However, the Board does perform a variety of other functions, as outlined later in this Report.

STRUCTURE OF THE BOARD

A. Coliste Barfett
ACTING CHAIRMAN

T. Donald Hetherington, Q.C.

Neil W. MacDonald

Robert D.S. Ward

James R. Dunstan

Bradley T. McManus, Q.C.

Terry C. Roberts

William Paterson
SECRETARY AND EXECUTIVE DIRECTOR

The Members

The Lieutenant Governor in Council appoints the Members of the Board and fixes their terms of office. These Members of the Board hold full time positions. One Member is appointed as Chairman of the Board and there is also provision for the appointment of one or more Vice Chairmen.

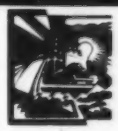
On April 25, 1991, Mrs. A.C. Barfett became Acting Chairman. Mrs. Barfett was first appointed to the Board in August of 1982, and was appointed Vice Chairman of the Board in January 1991. She replaces Mr. A.O. Ackroyd, who left the Board in 1991 after seven years of service as Chairman.

Two new Members were appointed in 1991, and are located in the Board's Calgary Office. By Order in Council 705/90 dated December 13, 1990, Mr. Bradley McManus was appointed to the Board, effective January 7, 1991. By Order in Council 532/91 dated August 15, 1991, Mr. Terry Roberts was appointed as a Member, effective September 1, 1991. These appointments maintained the number of Members at seven.

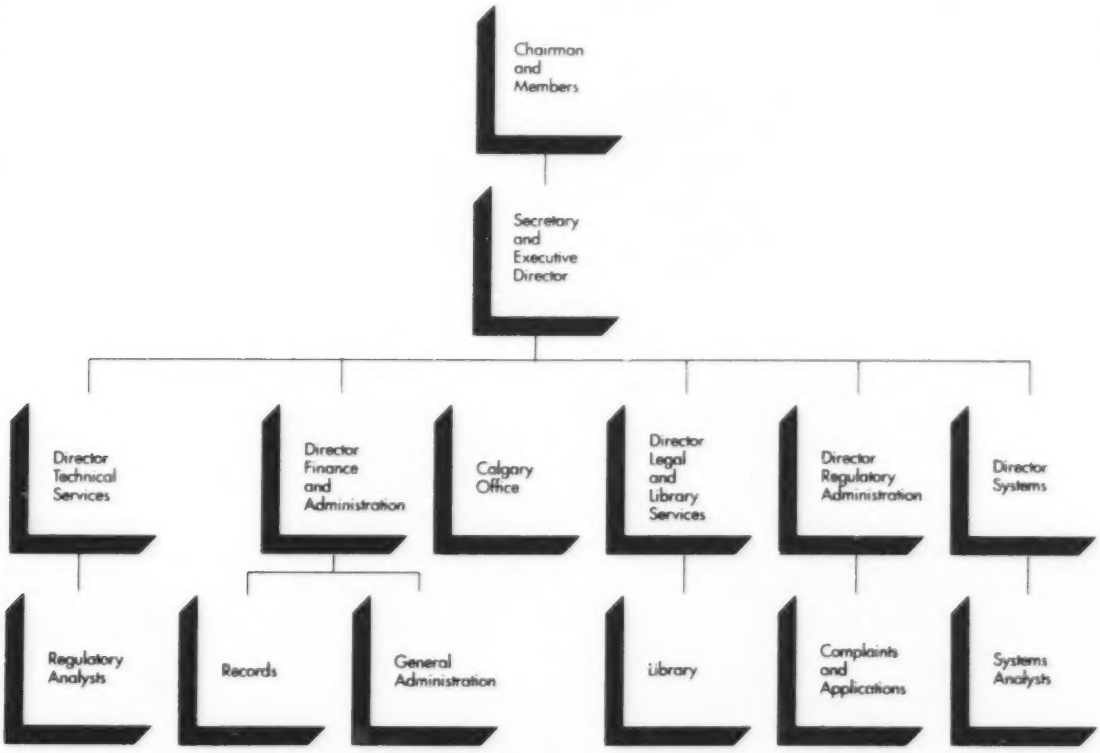
If additional Members are required on a part time basis, the Chairman may name Acting Members, to act for any period of time or on any matter, from a list of potential Acting Members nominated by the Lieutenant Governor in Council. No Acting Members were required in 1991. At year end, the following three persons were available to be named by the Chairman:

K. J. Boyd
B. O. Archibald
J. Eugene Sekora

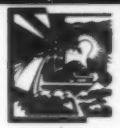
The Staff



At year end the Board had 44 authorized permanent staff positions, the majority of which are located in the Board's Edmonton Office. Reporting to the Secretary and Executive Director, the staff is organized into six main functional groups, as shown on the following organization chart. The Technical Services Division is responsible for the provision of technical support to the Board in the fields of accounting, engineering, and economics. The Regulatory Administration Division responds to public inquiries and complaints, and deals with applications of a non-technical nature. The Finance and Administration Division is responsible for internal financial matters, personnel and records. The operation of the Board's electronic data processing facilities is the responsibility of the Systems Division. The Board also has a Legal and Library Services Division. In addition, the Board maintains a small secretarial and administrative section in the Calgary Office.



The Board's Finances



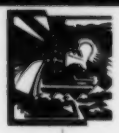
With respect to budgetary and administrative matters, the Board reports to the Lieutenant Governor in Council through the Minister of Energy. While in the past the Board was funded by the General Revenue Fund, the Board now receives about two thirds of its funding through assessments on those utilities over which the Board has jurisdiction. Section 40 of the Public Utilities Board Act provides that not less than one third of the Board's estimated expenditures shall be provided from the General Revenue Fund, while the remaining estimated expenditures will be provided from assessments and costs as ordered by the Board.

It is difficult for the Board to precisely forecast its supply and services expenditures in any given year, as these are directly related to the number, type, length and complexity of the public hearings which the Board must convene. However, as of December 31, 1991, the Board was within its total budget and did not expect any over-run at fiscal year end, as shown by the table following this section. The Board's financial records and accounts are subject to audit by the Auditor General of Alberta.

Expenditure Control Group	1990/91 Budget	1990/91 Expenditures (Actual)	1991/92 Budget	1991/92* Expenditures (Forecast)
1. Manpower	$2,595,000	$2,460,613	$2,650,000	2,650,000
2. Supplies & Services	330,000	312,753	292,048	292,048
3. Fixed Assets	40,000	181,878	7,952	7,952
TOTAL	$2,965,000	$2,955,244	$2,950,000	$2,950,000

* These amounts reflect actual expenditures for the period April 1, 1991 to December 31, 1991 plus estimated expenditures for the period January 1, 1992 to March 31, 1992.

1. Electric Utilities



There are two major investor-owned electric utilities under the full jurisdiction of the Board. TransAlta Utilities Corporation, which operates primarily in the southern and central areas of the province, serves customers directly, and also indirectly through wholesale contracts with municipally-owned distribution systems. Alberta Power Limited serves customers in the northern and eastern portions of Alberta.

The City of Edmonton owns and operates a fully integrated electric utility, Edmonton Power, which serves customers within its corporate limits. Pursuant to the Electric Energy Marketing Act, the Board is responsible for setting the price at which the City sells electric energy to the Electric Energy Marketing Agency, but does not establish end customer rates.

Both TransAlta and Alberta Power filed general rate applications with the Board in 1991, which included applications for interim refundable rates. Order E91035 dated June 5, 1991 approved a 7% across-the-board interim increase for Alberta Power, while Order C91024 dated June 6, 1991 approved a 7.15% across-the-board interim increase in TransAlta's rates.

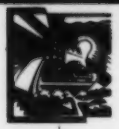
TransAlta's Phase 1 Decision E91093 dated December 16, 1991 established the company's rate base, fair return and revenue requirement for the 1991 and 1992 test years. In this Decision the Board reduced TransAlta's requested revenue requirement by approximately $48 million in 1991 and $49.5 million in 1992. While TransAlta requested a return on common equity of 14.25% for each year, the Board allowed a rate of 13.5% in 1991 and 13.25% in 1992. The Board also determined that TransAlta should use the flow through method to account for provincial income taxes. In addition, the Board allowed the inclusion of the Sheerness 2 generating unit into rate base commencing in 1992.

Alberta Power's Phase 1 Decision E91095 issued December 13, 1991. In this Decision, the Board established the company's rate base, fair return and revenue requirement for the 1991 test year. A Phase 1 Decision respecting 1992 was expected in the first quarter of 1992.

Full details respecting electric utility applications before the Board in 1991 are contained in Section 1 of Appendix 1.

2. Natural Gas Utilities

There are six investor-owned natural gas utilities which operate within Alberta, in addition to a larger number of municipally and cooperatively owned natural gas utilities which do not fall under the full jurisdiction of the



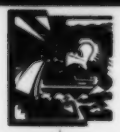
Board. The three major utilities regulated by the Board are Northwestern Utilities Limited (NUL), which operates primarily in the northern and central areas of the province; Canadian Western Natural Gas Company Limited (CWNG), which operates primarily in the south; and Centra Gas Alberta Inc. (formerly ICG Utilities (Alberta) Ltd.), which distributes natural gas to a number of smaller communities throughout the province.

CWNG, NUL and Centra were all before the Board in 1991. In 1989, the City of Calgary had filed an application requesting that the Board hold a hearing into the rates, tolls or charges for natural gas service provided by CWNG for 1989 and thereafter. This application was approved in Board Decision C89037 dated August 2, 1989. Consequently, CWNG submitted a general rate application on November 1, 1989. Phase 1 proceedings were held in 1990, and the Board rendered its Phase 1 Decision C90026 on July 27, 1990. Phase 2 proceedings were held in 1991. Phase 2 Decisions C91012 and C91013, dated March 28, 1991 and May 10, 1991 respectively, addressed the issues of rate design, terms and conditions of service and transportation rates.

Centra had also applied in 1989 for approval of a change in rates for the 1989 and 1990 test years. In Phase 1 Decision E90057, issued October 10, 1990, the Board set the Company's rate base and revenue requirement for the test years. Phase 2 proceedings were held in 1991, and Phase 2 Decision E91031 was issued July 18, 1991. In this Decision, the Board approved postage stamp rates for the company, as compared with the district rates previously in place. An irrigation rate was also established. Decision E91059 dated August 15, 1991 approved final residential rates for the company.

On July 2, 1991, Centra filed a general rate application with respect to the 1991 and 1992 test years. Centra also filed an interim rate application on the same date. Interim Decision E91067 dated August 28, 1991 approved an interim refundable rate increase for Centra. Centra's Phase 1 Decision was pending at year end.

NUL filed a general rate application with the Board on January 2, 1991. This application was later amended to include a request for interim rates to recover approximately 40% of the Company's projected 1991 revenue shortfall. In Order E91028 dated May 1, 1991, the Board approved NUL's proposed interim rates, noting that these rates should facilitate rate smoothing. In Phase 1 Decision E91044 dated November 18, 1991, the Board established NUL's revenue requirement for the 1991 and 1992 test years. In this Decision, as amended by Decision E91094, the Board reduced NUL's



projected revenue requirement for 1991 by approximately $9 million and by approximately $12 million for 1992. Among the key issues were depreciation expense, the proper rate of return on equity and the proper method of weather normalization. Forecasts of normal degree days play an important role in the forecasts of a gas utility's revenues. While the Board rejected the exponential weighting method proposed by NUL, which would have placed the most emphasis on weather conditions for the last three years, it did find that a shorter twenty year rolling average was more appropriate than the existing 50 year rolling average for determining a "normal" year. The Board accepted most of NUL's proposals with respect to depreciation, but reduced some costs of salvaging assets. The Board also established a rate of return on the portion of rate base financed by equity at 13.75%. In response to the Phase 1 Decision, NUL filed an application for interim rates on November 29, 1991. This application was in process at year end.

A general rate application was also filed in 1991 by Elk Point Gas, Ltd., a small gas utility serving customers in the Town of Elk Point. Order E91071 dated August 30, 1991, approved an interim refundable rate increase for the utility. The Phase 1 decision was pending at year end.

Energy pricing has been an important issue in the natural gas field since the deregulation of natural gas pricing occurred in November of 1986. Both CWNG and NUL obtain a substantial portion of their gas requirements under long term contracts which require periodic price redetermination. In 1989, price renegotiations for the bulk of the utilities' gas supplied under the long term contracts were concluded for the 1988, 1989, 1990 and 1991 gas supply years. The pricing system was set at $1.65 per gigajoule in the winter months and $1.25 per gigajoule in the summer months, down from the previous level of $1.90 per gigajoule in the winter months and $1.40 in the summer months. This new pricing was incorporated in the rates of the two utilities during their Gas Cost Recovery Rate proceedings.

Details of these and all other natural gas applications are contained in Section 4 of Appendix 1.

3. Water Utilities

The vast majority of water utilities in Alberta are municipally-owned, and hence not subject to the full jurisdiction of the Board. However, a number of water-related matters were before the Board in 1991.

The Board continued its investigation of a complaint from several customers

of Acheson Park Water Corporation, a small investor-owned water utility operating in the County of Parkland, concerning the alleged imposition of unfair water rates. This application was in process at year end.

On July 22, 1991, the Board received an application from Bearspaw Aqua Ltd. for approval to increase the rates and charges currently set for the supply of water to customers within the Municipal District of Rocky View No. 44. The Board had scheduled a hearing to examine the issue of whether it had jurisdiction to regulate this company, when notification was received that Bearspaw was planning to sell its assets. Consequently, the hearing of this matter was in abeyance at year end.

In addition, applications were received in 1991 from municipalities wishing to enter into water supply and special franchise agreements with a new water utility, CU Water Limited. Applications from the Town of Tofield and the County of Strathcona No. 20 were in process at year end.

Details of these applications are contained in Sections 3 and 6 of Appendix 1.

4. Cross Canada Rate Comparison

The following graphs indicate how Alberta's regulated electric and natural gas utility rates compare with those established in other provinces. For comparative purposes, these graphs have been prepared assuming an annual consumption of 6000 kWh for electricity and 165 GJ for natural gas. The calculations are based on rates effective as of December 31, 1991, as researched by Board staff.

There are many reasons why rates vary within and among provinces. These factors must be kept in mind when viewing any rate comparisons. For example, with electric utilities, rates are affected by such variables as the size and density of the respective distribution areas, the sources and cost of power generation and the rate design criteria employed. Natural gas rates are impacted by such items as the cost of gas, transportation distances, rate design criteria and the mix of customer classes. Nonetheless, it is informative to note that Alberta's utility rates compare favourably with those found across the country.

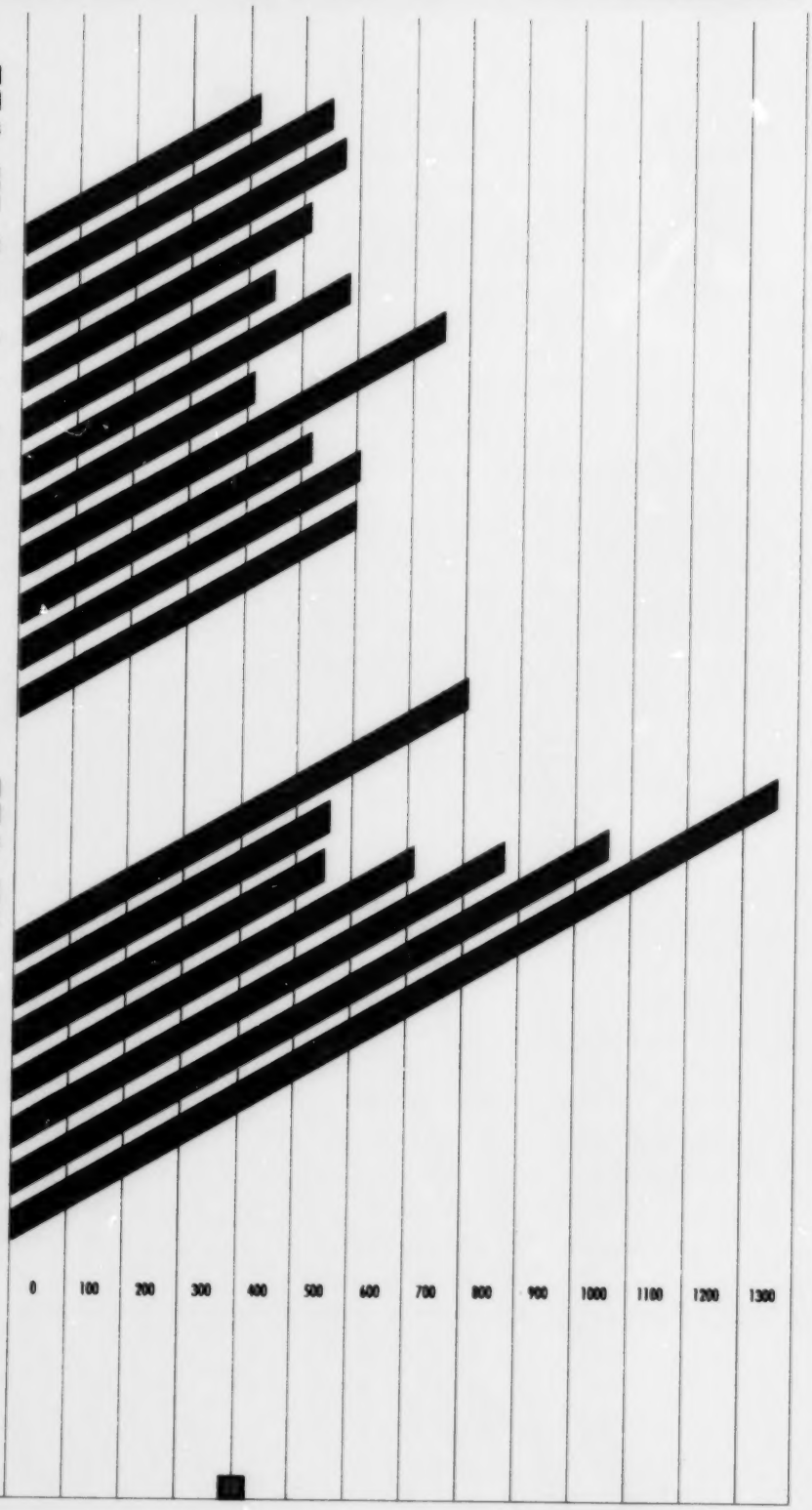
Cross Canada Rate Comparison

Average Annual Residential Electric Bills

Utility	Annual Bill (including 7% GST)
B.C. Hydro	$421.83
*TransAlta	$545.71
*Alberta Power	$569.29
Sask Power Corp.	$509.17
Manitoba Hydro	$445.59
Toronto Hydro	$589.68
Hydro Quebec	$407.33
Maritime Electric (P.E.I.)	$757.43
New Brunswick Power	$515.78
Nova Scotia Power	$603.96
Newfoundland Power	$599.11

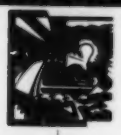
Average Annual Residential Natural Gas Bills

Utility	Annual Bill (including 7% GST)
Vancouver	$802.85
*Calgary	$566.06
*Edmonton	$558.36
Regina	$706.04
Winnipeg	$876.04
Toronto	$1,068.49
Montreal	$1,365.33



* Rates regulated by the Alberta Public Utilities Board

Interventions and Costs



Public involvement is an important facet in the effective operation of the regulatory process. The Board welcomes all constructive input respecting utility rates and terms and conditions of service.

In general rate applications, the Board finds interventions by different groups or members of the public useful and of assistance in testing the applicant's case. To ensure the fullest opportunity for public participation, the Board directs the applicant to publish notice of the proceedings in newspapers throughout the utility's service area, and to serve the notice on municipalities, public interest groups or other parties who have made their interest known to the Board.

Members of the Board's staff are assigned to each application before the Board, and the staff are available to answer any questions from the public. In addition, the Board has published brochures entitled "The Ratemaking Process" and "How to Intervene" to outline the relevant procedures to interested parties. These brochures are available free of charge from the Board's offices.

To further facilitate public participation, the Board may order that the applicant pay a portion or all of the intervenors' expenses. Section 60 of the Public Utilities Board Act provides the Board with discretionary authority to order that the costs incurred in connection with a rate application should be paid for by the utility and recovered through customer rates. However, the Act does not allow the Board to provide advance funding for any party considering intervention.

The Board recognizes that intervention, which is aimed at reducing utility rate increases, constitutes a cost which is ultimately added back to all customers' utility bills. Therefore, before exercising its discretion to award costs, the Board considers a number of questions, such as the effectiveness of the intervention, its relevancy to the issues, and whether the costs of the intervention were necessary and reasonable. Those who have a common interest in the proceedings are encouraged to co-ordinate their presentations so as to avoid duplication of effort and thereby minimize costs. Applications for costs are considered after the completion of the hearing process.

The Board has recently inaugurated the use of a Scale of Costs, which sets a cap on professional fees that will be awarded by the Board, and outlines those disbursements which will be considered for reimbursement. This Scale was first approved on May 1, 1989 and was revised effective August 1, 1991. A copy of the Scale of Costs may be

obtained from the Board's offices.

In 1991, interventions were lodged by a variety of parties, including municipalities, institutional groups, consumer associations, and individual customers. During the course of the year, the Board granted costs awards to intervenors in connection with a number of rate applications. While cost orders respecting certain 1991 proceedings were pending at year end, the Board in 1991 awarded intervenors' costs of $1,592,927.25. In addition, the Board awarded applicant external costs in the amount of $688,546.02.

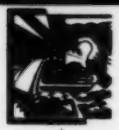
Public Inquiries and Complaints

The Board deals with inquiries and questions from the public respecting any aspect of utility service. The Board makes every effort to respond to these inquiries in a prompt and informative manner. A brochure entitled "Making a Complaint" is available from the Board's offices to assist in this process.

An important aspect of the Board's role in this regard is to assist consumers in understanding how a utility operates. Consequently, telephone complaints may sometimes be resolved by the provision of information respecting utility rates or terms and conditions of service. In other cases, the complainant may be referred to the utility company in question for further information. If the matter cannot be resolved by these means, the customer will be asked to submit a written complaint. Written complaints are usually investigated with the utility company, and occasionally a public hearing may be required to resolve the dispute.

In 1991, Board staff received a total of 221 complaints by telephone and 43 written complaints, as well as a large number of general inquiries. Only one public hearing was held in 1991 respecting a customer complaint. A commercial customer in Red Deer lodged a complaint with the Board concerning the billing practices and security deposit policy of Northwestern Utilities. The Board held a hearing in Red Deer to examine the complaint, and upheld the utility's right to collect arrears from the complainant. However, the Board did find fault with the communication of Northwestern's policies in this instance, and suggested that the Company might wish to consider the adoption of written service contracts for commercial accounts, as well as the provision of further documentation respecting its security deposit policy.

In addition to holding formal public hearings, the Board on occasion made use of informal meetings between complainants and representatives of the utility companies involved to try to resolve disputes.

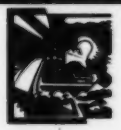


Of the 43 non-registered written complaints dealt with by the Board, 15 dealt with rate increases. In addition, 27 complaints were received by telephone with respect to utility rate increases, while a further 33 telephone complaints dealt with increases in minimum milk prices. At year end, all of the complaints received by telephone were resolved, while 5 of the written complaints remained under investigation.

The following table contains a breakdown of the complaints received by the Board in 1991.

Type of Utility	Nature of Complaint	Written	Telephone
Electric	High rates/bills	3	19
	Rate increases	13	19
	Disconnection	1	6
	Construction Contributions	0	4
	Miscellaneous	6	14
Gas	Disconnection	1	11
	High estimates/bills	1	12
	Security deposits	0	10
	Rate increases	2	8
	GST applied to bills	1	8
	Late payment penalties	0	7
	Billing disputes	1	7
	Internal policies	0	3
	Miscellaneous	2	15
Other (Gas	Milk rate increases	0	33
Co-ops,	Other rate increases	1	10
Municipalities,	Billing disputes	4	10
Milk, AGT, etc.)	Disconnection	0	6
	Rate structure	3	5
	Miscellaneous	4	14
		43	**221**

OTHER FUNCTIONS AND RESPONSIBILITIES



While rate-making is the most widely known activity of the Board, the Board performs a number of other important functions, some of which are described in detail below.

1. General Supervision of Utilities

The Board is required by statute to exercise a general supervision over utilities within its jurisdiction, and to ensure their compliance with the law. As part of the regulatory process, the Board is also responsible for reviewing the affairs, earnings and accounts of each owner of a public utility or gas utility within three years of fixing their rates. To ensure compliance with the mandatory review requirements, the Board selects utilities to be reviewed during a given year and authorizes technical staff analysts to proceed with the necessary inquiries.

The consideration of a utility's general rate application also provides an opportunity for the necessary review through the public hearing process, since a thorough examination of the utility's operations is required for the determination of a rate base and fair return. Consequently, the Board's review schedule is under constant revision as general rate applications are processed, thereby satisfying the formal review requirements.

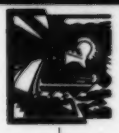
A report on the review of the affairs, earnings and accounts of Grande Prairie Transmission Co. Ltd. was completed in 1991. A review of Elk Point Gas, Ltd. was in progress at year end.

2. Municipal Supply Contracts and Special Franchise Agreements

Pursuant to sections 279 and 280 of the Municipal Government Act, a municipality must obtain the approval of the Board to enter into a supply contract or a special franchise agreement with a public or gas utility. Renewals or alterations of such contracts must also receive Board approval, pursuant to section 281 of the Municipal Government Act.

A supply contract grants a utility company the right to provide utility services for distribution by the municipally owned utility system. A franchise agreement generally provides the utility company with the exclusive right to directly supply and serve customers within the specified franchise area.

Applications for approval of a franchise agreement often include applications for approval of a franchise tax. Pursuant to the Municipal Taxation Act, a municipality may elect to have a utility company pay the municipality a tax equal to a fixed percentage of its gross revenue realized within the municipality, in lieu of property tax. The level of this franchise tax varies between communities. For example, the amount of this municipal franchise tax for gas utilities in Alberta's major cities is 10% of the gas bill including the franchise



tax. Because of the impact on customers' bills, the Board requires the utility companies to show the amount of the franchise tax as a separate item on utility bills. In cases where the municipality applies to increase the level of the franchise tax which is paid by the utility, the Board has taken steps to ensure that notice is provided to the customers of the dollar impact of the proposed change.

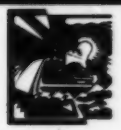
Section 3 of the Gas Utilities Statutes Amendment Act, which was proclaimed in 1990, extended the application of the franchise tax provisions of the Municipal Taxation Act to transportation customers. For this purpose, the Board must establish, for each year, a deemed value for the natural gas volumes transported through transportation service, which is then to be multiplied by the quantity of gas being transported. This amount is included in the calculation of the utility company's gross revenues, and is thus subject to the franchise tax. Hearings were held in 1991 respecting the method of calculating the deemed value. In Decisions C91018 and C91019, the Board approved the methodology proposed by Canadian Western Natural Gas Company Limited and Northwestern Utilities Limited, namely calculating the deemed value as the difference between the "Total Energy Charge" for Rate 2 and the "Base Variable Charge" for Rate 12.

During 1991, the Board heard a number of supply contract and special franchise applications, as outlined in Section 6 of Appendix 1. To facilitate consumer representation, in 1991 a number of these hearings were conducted in the municipalities involved.

One of these hearings involved an application from the Town of Stony Plain for approval to enter into a natural gas supply and special franchise agreement with West Parkland Gas Co-op Ltd. respecting lands annexed by the Town in 1979 and 1981. The remainder of the municipality is served by Northwestern Utilities Limited. Northwestern had appeared at an earlier hearing to oppose the application, asserting that the Board lacked the jurisdiction to grant such an application pursuant to the Municipal Government Act. In its Decision E91086, the Board approved the application. The Board found that it had jurisdiction to hear the application and that approval was appropriate under the circumstances.

3. Milk Prices

Under the Dairy Board Act, the Board has set the minimum price of fluid milk that may be paid to producers, and the minimum wholesale and retail prices of fluid milk and fluid milk products that may be charged by processors, distributors and retailers. However, in 1991 the Government of Alberta deregulated the minimum retail price of milk.



By Order in Council 424/91 dated June 27, 1991, the Lieutenant Governor in Council amended the Dairy Control Board Regulation, to exclude a milk product when sold at the retail level in its definition of "milk". Therefore, the Board no longer has jurisdiction to prescribe the minimum retail price of milk and milk products.

Prior to the issuance of this Order in Council, the Board had issued its final decision respecting an application received in 1989 from certain milk processors and distributors for approval of an increase in the minimum wholesale and retail price of fluid milk and milk products. In Decision E91008 dated February 19, 1991, the Board approved a further one cent per litre increase in the minimum wholesale and retail price of milk. This increase was in addition to the interim increases of one cent per litre approved effective December 15, 1989 and effective December 1, 1990. On May 24, 1991, the Board also established interim minimum wholesale and retail prices for fluid milk packaged in four litre plastic jugs.

The Board continues to regulate minimum producer and wholesale prices for fluid milk. Since 1976, the Board has used the fluid milk pricing formula, developed with the assistance of the Production Economics Branch of the Alberta Agriculture Department, to help determine the minimum producer price of milk. In Decision E76104 dated August 13, 1976, the Board stated:

"The Board will continue to use formula pricing as a guide in fixing the minimum price to be paid to producers for Class 1 fluid milk.

The Board reserves the right to adjust or not to adjust the minimum producer price as indicated by the formula price if it finds that unusual circumstances prevail at any particular time. The performance and results of formula pricing will be monitored continuously, tested against the production cost study annually and reviewed at public hearings periodically in response to an application or upon the Board's own initiative."

In 1989, Board staff reviewed the formula and concluded that it remained a viable pricing indicator. Certain changes in the minimum producer prices of milk have been approved by the Board as a result of the application of this fluid milk pricing formula. For example, Order E91012 dated March 1, 1991 approved an increase of $0.98 per hectolitre in the minimum producer price and a one cent per litre increase in the minimum wholesale and retail prices of fluid milk, effective March 15, 1991.

Orders resulting from the Board's milk pricing activities are summarized in Section 7 of Appendix 1.

4. Duties Pursuant to the Electric Energy Marketing Act

The Board is required, pursuant to the Electric Energy Marketing Act, to set the price or the pricing formula for each consumer group at which electric energy will be sold to the Electric Energy Marketing Agency.

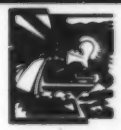
The Electric Energy Marketing Act, which became effective September 1, 1982, requires TransAlta Utilities Corporation, Alberta Power Limited and Edmonton Power to sell all the electric energy generated by these utilities, for consumption within Alberta, to the Electric Energy Marketing Agency at prices established annually by the Board. These prices are based upon the cost of generating and transmitting electric energy to the designated pooling interface points. The Agency pools these costs and resells the electric energy to the three utilities at an average price. To the extent that this process averages generation and transmission costs there is a measure of equalization of costs throughout Alberta, but the exclusion of distribution costs results in some variation in rates for customers in different areas.

Effective July 2, 1991, responsibility for administering the Electric Energy Marketing Act was transferred from the Alberta Electric Energy Marketing Agency to the Alberta Department of Energy. The elimination of the Agency has not affected pricing practices and procedures.

Filings were received in 1991 from Alberta Power, Edmonton Power and TransAlta requesting the Board to determine the prices at which these utilities would sell electric energy to the Electric Energy Marketing Agency during 1992. In 1993 the Board may adjust these prices to reflect the utilities' actual costs.

Furthermore, a joint application by Alberta Power, Edmonton Power and TransAlta was received on May 31, 1991 for an order adjusting the price or pricing formula to the Agency for 1990.

The Board held a concurrent public hearing for both of these proceedings and issued Board Decision E91074 dated December 13, 1991. This decision set out the principles by which the prices are established, and the Board's reasons with respect to the applications. Orders E91100, E91101 and E91102 dated December 31, 1991 established the forecast 1992 prices for Alberta Power, Edmonton Power and TransAlta respectively. Order E91103 dated December 31, 1991 established the adjusted prices for 1990 for each of the utilities.



Further details respecting Electric Energy Marketing Act applications are contained in Section 2 of Appendix 1.

5. Municipally-Owned Utilities

Municipally-owned utilities are not subject to the full jurisdiction of the Board, unless they pass a by-law submitting the operation of their utilities to the control and orders of the Board. At present, no municipalities are under the full jurisdiction of the Board. However, pursuant to Section 291 of the Municipal Government Act, a user of a municipally-owned utility (with the exception of 'edmonton telephones'), may lodge a complaint with the Board alleging that the rates of the utility do not conform to the rate structure established by the municipality; have been improperly imposed; or are discriminatory. If the Board concurs it may vary or disallow these charges.

A number of complaints were received by the Board in 1991 pursuant to this section. For example, the Board received several complaints respecting municipal water rates and billings. Further details of complaints respecting municipally-owned utilities are contained in Section 6D of Appendix 1.

In addition, the Board hears and determines disputes with respect to the rates charged for utility services provided by one municipality to another municipality. No such applications were received in 1991.

6. Rural Gas Utilities

Rural gas utilities are not subject to the jurisdiction of the Board, except where specifically provided in the Rural Gas Act. Section 37(1)(b) of this Act provides that the Board may hear and resolve complaints with respect to the rates imposed by rural gas utilities when it is alleged that such rates do not conform to the rate structure established by the utility; have been improperly imposed; or are discriminatory. No such hearings were held in 1991.

Furthermore, the Board sits as an appellate tribunal with respect to disputes over service area boundary decisions made by the Chief Officer as defined in the Rural Gas Act. No such applications were received in 1991.

7. Intra-Provincial Railways

The definition of a public utility contained in the Public Utilities Board Act includes a system which conveys travellers or goods over a railway. Such systems are required to file rates with the Board and such rates cannot be changed without Board approval. In the past year Central Western Railway has filed its rates with the Board.

In addition, Section 95 of the Public Utilities Board Act specifies that the permission of the Board must be obtained for the construction of highway crossings by a railway company within the legislative authority of Alberta, and that the Board shall make

reasonable provisions for the protection of the travelling public with respect to these grade crossings. No such applications were received in 1991.

8. NOVA Corporation of Alberta

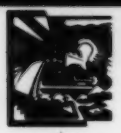
The Board hears and resolves complaints with respect to the rates charged by NOVA Corporation of Alberta for the transportation of gas within Alberta. Section 37(2) of the NOVA Corporation of Alberta Act provides that, upon complaint in writing of an interested party, the Board is responsible for determining the justness and reasonableness of the rates, tolls or other charges fixed or varied by NOVA, and by order in writing may vary or confirm the foregoing rates, tolls or other charges. Three such complaints were filed with the Board on December 30, 1991, and will be dealt with in 1992.

9. Compensation Fixing Duties

A number of statutes confer compensation fixing duties upon the Board. For example, the Board hears and determines disputes with respect to the payment of compensation which may be required when all or part of a franchise area of a rural gas utility is annexed to a municipality and becomes served by another utility. In addition, the Board may determine compensation respecting the sale of Rural Electrification Association assets. When directed by the Lieutenant Governor in Council, the Board may also fix compensation with respect to air pollution damage claims, water pollution damage claims and environment damage claims. No such applications were received by the Board in 1991.

10. Appeals of the Alberta Cost of Service

Under the Natural Gas Pricing Agreement Act and Regulations, the Board acted as an appellate tribunal with respect to determinations of the "Alberta Cost of Service" made by the Alberta Petroleum Marketing Commission prior to October 31, 1987 with respect to the transportation of gas within Alberta. Such an appeal was lodged in 1990 by R.W. Berry, Duhamel Resources Ltd. and Choya Petroleum Ltd. respecting the Alberta Cost of Service determination for TransCanada PipeLines Limited for the period of February 1983 to April 1987. Board Decision C91034 dated August 30, 1991, dismissed the appeal, on the grounds that the companies had failed to meet the basic statutory requirements and that therefore the Board was without jurisdiction to consider the appeal. In addition, in 1991 Westcoast Energy Inc. filed an appeal with respect to the Alberta Cost of Service determination for Husky Oil Operations Ltd. and other Savanna Creek Producers for the period of February 1980 to December 1981. This appeal was in process at year end.



Under the Natural Gas Marketing Act, the Board sits as an appellate tribunal for determinations of the "Alberta Cost of Service" made by the Alberta Petroleum Marketing Commission. No such appeals were received by the Board in 1991.

11. The Energy Resources Conservation Board Hearings

Order in Council 234/85 provides that certain members of the Board are nominated as persons who may be selected as Acting Members of the Energy Resources Conservation Board (ERCB). No such Acting Member appointments were made in 1991.

12. Gas Processing Costs

Section 10 of the Gas Utilities Act states that, subject to the authorization of the Lieutenant Governor in Council, the Board may fix the costs, or method for ascertaining costs, for the gathering, treating or processing of gas. Certain applications pursuant to this section were under Board consideration in 1991.

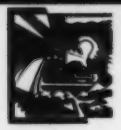
13. Inquiries

From time to time the Board, on its own initiative or at the request of the Lieutenant Governor in Council, may hold public inquiries into matters of topical concern which fall within its jurisdiction. No such inquiries were held in 1991.

14. Small Power Filings

Pursuant to the Small Power Research and Development Act, contracts entered into between owners of eligible small power production facilities and utility companies must be in a form that is satisfactory to the Board. All such contracts must therefore be filed with the Board for its review. The Board received a number of such filings in 1991, all of which were found to be acceptable by the Board.

SUMMARY OF REGULATORY ACTIVITY - 1991



This table provides some selected statistics which describe the volume of regulatory activity during 1991 in the same categories used in Appendix 1, "Applications to the Board".

	APPLICATIONS CARRIED FORWARD FROM 1990	APPLICATIONS RECEIVED DURING 1991	TOTAL APPLICATIONS TO BE DEALT WITH IN 1991	APPLICATIONS FINALIZED BY BOARD ORDERS OR DECISIONS	APPLICATIONS FINALIZED WITHOUT BOARD ORDERS OR DECISIONS	TOTAL APPLICATIONS FINALIZED IN 1991	APPLICATIONS CARRIED FORWARD TO 1992	DAYS OF FORMAL HEARINGS	DAYS OF IN-OFFICE HEARINGS
1. Electric Utilities	5	15	20	12	1	13	7	34	2
2. Electric Energy Marketing Act Proceedings	4	5	9	5	0	5	4	6	0
3. Water Utilities	1	2	3	0	0	0	3	1	0
4. Natural Gas Utilities	8	30	38	23	0	23	15	37	1
5. Utilities not offering utility services to the general public	0	14	14	14	0	14	0	0	13
6. Municipalities 6A. Special Franchise Agreements	13	47	60	39	1	40	20	2	18
6B. Supply Contracts	2	3	5	4	0	4	1	0	1
6C. Supply and Lighting Agreements	8	14	22	22	0	22	0	0	0
6D. Complaints	0	1	1	0	0	0	1	0	0
6E. Other Applications	0	0	0	0	0	0	0	0	0
7. Milk Pricing	2	3	5	4	0	4	1	0	0
8. Other Matters	3	4	7	1	1	2	5	1	0
Totals	46	138[1]	184	124[2]	3[3]	127	57[4]	81	35

1 Includes cases where the Board acted on its own motion and matters which were referred back to the Board by the Courts.

2 In 1991, 160 Orders and Decisions were issued by the Board. In 1990 there were 151 Orders and Decisions issued.

3 Includes applications withdrawn by the applicant.

4 Some applications reflected have been partially dealt with by Board Orders and Decisions but are not yet finalized.

APPENDIX 1 Applications to the Board

APPLICATION PARTICULARS
A REGULATED ENTITY
REGISTRATION NUMBER / FILE NUMBER
B SUBJECT MATTER NUMBER
C DISPOSITION / REFERENCE

Section 1: Electric Utilities

Data reported in groups arranged alphabetically according to the name of the regulated utility to which the application refers. Individual applications within the group are then arranged in order of registration number.

1.1 A **Alberta Power Limited**
RE89044 / E3.5.89-628 (Costs)
B The determination of intervenor and applicant's external costs respecting APL's 1989/1990 Phase 2 proceeding and Phase I review and variance proceeding.
C Decision E91027 dated April 16, 1991, as amended by Order E91029 dated May 6, 1991, approved applicant and intervenor fees and disbursements of $582,452.23. The Board disallowed certain costs which were not in accordance with the Board's Scale of Costs.

1.2 A **Alberta Power Limited**
RE90091 / 900080 2090 5 2
B The City of Calgary applied to change the method by which income taxes are accounted for by APL for 1990 and onwards. The City of Calgary sought to review and vary the 1990 revenue requirement approved for APL in Decision E89095 as amended by Order E90013 and Decision E90054.
C Decision E91023 dated March 22, 1991 denied the City of Calgary's request to review and vary Decision E89095 as amended by Order E90013 and Decision E90054. The City of Calgary had proposed that APL change its method of accounting for income tax in the determination of the utility revenue requirement from the Normalized All Taxes Paid method to the Flow-Through Method.

1.3 A **Alberta Power Limited**
RE91002 / 910005 2090 5 2
B For approval to implement an energy efficient motor incentive program.
C Decision E91007 dated February 22, 1991 approved an addition to APL's electric service regulations allowing for rebate payments to customers who purchase high efficiency electric motors.

1.4 A **Alberta Power Limited**
RE91019 / 910083 2050 5 2
B For approval of a change in the existing rates, tolls and charges for electric light, power or energy furnished to its customers in Alberta for the 1991 and 1992 test years.
C1 General
(a) Interim Order E91035 dated June 5, 1991 approved an interim refundable across-the-board 7% rate increase.
(b) Phase 1 Decision E91095 dated December 13, 1991 approved a rate base, fair return and revenue requirement for the 1991 test year. Details are noted below. Due to the timing of a significant change in APL's 1992 sales forecasts, the Phase 1 Decision respecting 1992 was pending at year end.
(c) Phase 2 proceedings will be scheduled in 1992.
C2 Rate Base
(a) General
The Board determined the mid-year rate base to be $1,446,444,000. The Board reduced APL's proposed opening balance for plant in service by $730,000 because the opening balance was overstated as a result of an over-allocation of ES&G in 1990. The Board affirmed its finding made in Decision E89095 that a reduced AFUDC rate should be used to calculate the AFUDC on Sheerness Unit II. The Board considered that, if APL considered that service and back up requirements were sufficiently met within its original forecast, then extra isolated plant additions that exceeded those requirements could not be justified. Therefore, the Board reduced APL's rate base transfers by $60,000. The Board considered that an Alberta company such as WESCUP arranging out of province sales should pay a fair rate for electrical service that reflects the incremental cost burden to AIS customers and pro-

vides a fair contribution to AIS fixed costs. The Board directed APL to establish a separate wholesale customer class for WESCUP, and to file with its Phase 2 evidence a complete analysis of the costs of serving WESCUP, including line losses.

(b) Hotchkiss-Hamburg-Ring Creek Project

The Board considered that the Hotchkiss-Hamburg-Ring Creek project would not qualify as a system addition until at least 1994. The Board increased APL's mid-year contributions by $0.85 million to reflect the higher contribution that would have been required from Shell and Canadian Hunter had the project been considered an early system investment until 1994.

(c) Depreciation

The Board determined year-end accumulated depreciation to be $576,503,000. The Board accepted the Company's proposed 35 year service life for steam production units. The Board considered it appropriate to match depreciation expense to the useful life of the property to the greatest extent possible. The Board found the Company's use of truncated survivor curves for establishing depreciation expense for production plant to be consistent with the matching principle. The Board accepted the Company's methodology for establishing life and dispersion characteristics of mass property over the methodology proposed by the MI. The Board considered that more retirement experience was incorporated in the Company's analysis, and that the evidence showed that APL had exercised sound judgement in its selection of life and dispersion characteristics. The Board rejected the recommendations of the MI that net salvage for mass property should be set at higher levels than proposed by the Company. The Board noted that for certain mass property accounts APL proposed gross salvage levels that fell within the range of net salvage contained in the relevant data. The Board found insufficient evidence to support the levels proposed by APL and therefore approved net salvage levels based on the dollar weighted gross salvage experience contained in the data. The Board reduced APL's depreciation expense by $874,639 to reflect this adjustment. The Board affirmed the Company's use of the Equal Life Group (ELG) depreciation calculation procedure over the use of the Average Life Group (ALG) procedure because the Board found that the ELG procedure provides a better match between depreciation charges and the useful life of the property.

(d) Necessary Working Capital

The Board determined necessary working capital to be $8,801,000. The Board considered that amortization of project software costs should be over the projects' useful lives even when greater than 5 years. The Board excluded the unamortized software development costs associated with the customer billing, financial management and human resources systems from the 1991 necessary working capital because the in service dates for these projects were after 1991. The exclusion of these costs resulted in a $1,203,000 reduction to necessary working capital.

C3 Return on Rate Base

The Board determined a forecast capital structure excluding CIAC of 45.51% debt, 22.95% preferred stock, 31.21% common equity, and 0.33% no-cost capital. The Board determined that contributions in the amount of $106,078,000 were available to finance rate base. The Board fixed a rate of return on common equity of 13.5%. The Board considered that this rate of return would maintain APL's financial integrity since it would be commensurate with rates of return earned by companies of similar risk. The Board reduced APL's forecast embedded cost of debt from 11.351% to 11.323% to reflect a lower than forecast rate on its the 1991 debt issue. The Board accepted APL's forecast embedded cost rate of 8.316% for preferred stock. The Board determined a total fair return on rate base of $151,029,000.

C4 Revenue Requirement

The Board approved a total revenue requirement of $465,661,000. The Board reduced APL's revenue requirement by $167,000 to reflect the 1992 Sheerness 2 insurance costs incorrectly included in revenue requirement. The Board reduced APL's proposed revenue requirement by $161,000 to reflect the amortization against coal costs of an $807,000 reclamation credit over five years commencing in 1990. The Board found that the reclamation credit constituted an extraordinary credit and considered that such credits should receive a similar treatment to extraordinary charges. The Board reduced APL's proposed reve-

nue requirement by $433,000 to reflect the determination of a higher vacancy rate it used in the calculation of labour expense. The Board accepted the vacancy rate of 3.2% proposed by the MI as a reasonable compromise between the Company's forecast of 2.3% and the historical average of 4.1%.

The Board directed APL to record in each year the difference between actual and forecast B.C. Hydro revenues in a deferral account. The disposition of any amounts in this deferral account are to be dealt with at the time of APL's next GRA. The Board expressed concern that APL's adjustment for changing capacity factors in the calculation of average other production O&M might understate the variable production O&M costs in those years in which capacity factors are being adjusted upwards. Further, APL's calculation which only adjusted data from 1989 forward might overstate the cost per kWh in the unadjusted years prior to 1989. The Board considered that an average production O&M cost per kWh, calculated using 6 years cumulative constant dollar production O&M, divided by APL's capacity factor adjusted kWh, cumulative for the same six years, would address the Board's concerns. Further the Board considered that adjustments for extraordinary items such as inventory accounting changes and ash haul expenses were necessary in order to compare historical levels of other production O&M. The effect of the Board's determination was a reduction in APL's proposed other production O&M of $1,586,000. The Board found that APL's proposed 16% increase in marketing and public information expense was not shown to be warranted by the evidence. The Board reduced the increase to 5% resulting in a reduction to APL's proposed O&M of $535,000.

The Board noted that the circumstances under which the Board found the use of the NATP income tax method to be appropriate no longer existed with respect to provincial income tax. The Board found that the NATP income tax method was still appropriate for federal income tax calculations. The Board considered it inappropriate to approve a revenue requirement which was greater than required and rejected APL's deferred provincial tax proposal. The Board considered that the Company's interest coverages would remain adequate with a change to the flow-through method for provincial income taxes and approved a change to the flow-through method for provincial income taxes. The Board also considered that APL should maximize its CCA claim on mining assets again considering it inappropriate to approve a revenue requirement which was greater than required. The net effect of using flow-through for provincial income taxes, and maximizing CCA, together with any income tax effects arising from the Board's findings with respect to other matters was a reduction in income tax expense of $20,969,000.

C5 Revenue

The Board determined revenues at existing rates to be $455,471,000 and revenues from the interim rate increase to be $14,650,000. The Board found a revenue surplus of $4,460,000 for 1991.

1.5 A **Alberta Power Limited**
RE91028 / 910090 2090 5 2

B For approval of a change in rates relating to the Town of Swan Hills because of a change in the revenue tax rate.

C Approved / Order E91047 dated July 24, 1991.

1.6 A **Alberta Power Limited**
RE91034 / 910092 2090 5 2

B For approval of a change in rates relating to the Town of Fox creek because of a change in the revenue tax rate.

C In process at year end.

1.7 A **Alberta Power Limited**
RE91035/910093 2090 5 2

B For approval of a change in rates relating to the Village of Hairy Hill because of a change in the revenue tax rate.

C Approved / Order E91069 dated August 30, 1991.

1.8 A **Alberta Power Limited**
RE91036 / 910094 2090 5 2

B For approval of a change in rates relating to the Village of Elnora because of an introduction of a revenue tax.

C In process at year end.

1.9 A **Alberta Power Limited**
RE91049 / 910036 2230 5 2

B For an order of the Board approving the purposes of, and authorizing the issue of 3,000,000 Series P Preferred Shares for $75,000,000 to Canadian Utilities Limited.

C Approved / Order E91065 dated August 15, 1991.

1.10A **Alberta Power Limited**
RE91067 / 910117 2090 5 2

B For approval of a change in rates relating to the City of Grande Prairie because of a change in the revenue tax rate.

C In process at year end.

1.11A **Alberta Power Limited**
RE91089 / 910033 2230 5 2

B For an order of the Board approving the purposes of and authorizing the issue of a 9.2% debenture to Canadian Utilities Limited.

C Approved / Order E91104 dated December 19, 1991.

1.12A **TransAlta Utilities Corporation**
RC91009 / 910063 2230 6 2

B For an Order of the Board approving the purposes of and authorizing the issue of 4,000,000 8% First Preferred Shares having an aggregate stated capital amount of $100,000,000.

C Approved / Order C91017 dated April 22, 1991.

1.13A **TransAlta Utilities Corporation / Border Power Ltd.**
RC91022 / 910100 2240 8 2 / 910100 3205 6 2 / 910100 3205 8 2

B Application by TransAlta on its own behalf and on behalf of Border for an order authorizing the transfer on the books of Border of all of the capital stock of Border to TransAlta, and declaring that, for the purposes of the acquisition of Border by TransAlta, sections 91.1(2)(d) and 99 of the Public Utilities Board Act do not apply to TransAlta or to Border.

C Approved / Decision C91032 dated July 26, 1991.

1.14A **TransAlta Utilities Corporation**
RE89032 / E3.6.89-21B (Costs)

B Additional Intervenor costs arising from TransAlta's 1988/1989/1990 Phase 2 application.

C In Decision E91033 dated June 12, 1991, the Board fixed and approved for payment additional Intervenor costs of $3,181.75. These were submitted after the cost proceedings which led to Decision E91006, dated February 6, 1991. The Intervenors, Crowsnest Pass and Willow Creek REA, had submitted $3,796.75 in costs.

1.15A **TransAlta Utilities Corporation**
RE90064 / 890023 2170 6 3

B Application dated November 1, 1990 by the City of Calgary for a review and variance of Decision E89091, dated December 15, 1989, as amended by Order E90014, dated February 7, 1990; or, alternatively, to fix the rates, tolls and charges of TransAlta pursuant to section 81 of the Public Utilities Board Act.

C In Order E91030, dated May 13, 1991, the Board denied Calgary's application to review because the application met none of the criteria used by the Board as a basis to review a decision. The Board also denied Calgary's alternate application because the accounting change initiated by TransAlta with respect to its unbilled revenues was not approved by the Board for regulatory purposes. Therefore, the accounting change did not affect the Board's determination of revenue requirement or rates with respect to 1990. The Board did agree with those parties who submitted that a decision was required as to whether shareholders or customers are entitled to the revenues that arise from unbilled consumption. The Board found that, since customers prepay the costs associated with unbilled consumption, customers should be entitled to receive the funds associated with unbilled consumption when unbilled revenues are accrued into test year revenues for regulatory purposes. As long as revenues associated with unbilled consumption are not accrued into test year revenues, the funds that customers provide to prepay the costs associated with unbilled consumption are recognized for regulatory purposes in the determination of

working capital. The Board did not agree with TransAlta's characterization that treating these funds associated with unbilled consumption as customer provided funds amounts to retroactive ratemaking. The Board considered that, if unbilled revenues are accrued for regulatory purposes on a going forward basis, there should be no restatement of historical results for regulatory purposes. The Board considered that the funds associated with unbilled consumption would be revenues only when the company began to accrue unbilled revenues for regulatory purposes. The Board considered that the generally accepted accounting principles (GAAP) do not determine whether customers or shareholders are entitled to the benefits of the funds associated with unbilled consumption. Once the regulatory determination of entitlement is made, GAAP applied to a regulated industry would require the recording of data in accordance with determinations of the regulator. The Board agreed with TransAlta that the method which provides the best estimate of the revenues associated with unbilled consumption is TransAlta's Billing Method.

The Board considered that, if TransAlta proposed not to accrue unbilled revenues for regulatory purposes, the findings of Decision E89091 should continue to apply. The Board considered that, should TransAlta propose to accrue unbilled revenues for regulatory purposes, the following directions would apply for regulatory purposes: (1) the estimated amount of the unbilled revenue balance at the beginning of the test year, determined by TransAlta's Billing Method, be recorded in a utility deferred revenue account; (2) the positive or negative growth in unbilled revenue valued at proposed test year rates be included in test year utility revenues along with billed revenues for rate setting purposes; (3) the utility deferred revenue account be amortized into test year revenues, for rate setting purposes, on a prospective going-forward basis at a rate to be proposed by TransAlta and approved by the Board in a future GRA; (4) the adjustment to the revenue lag in the lead-lag study be no longer required; and (5) the test year average unamortized amount of customer supplied funds in the utility deferred revenue account be considered as no-cost capital in the determination of fair return on rate base.

The Board considered that the above directions would provide the consistency to ensure that the regulatory accounting of actual results match the method by which rates are fixed by recognizing either the accrual or non-accrual of unbilled revenues. The Board also considered that the foregoing advice and direction to TransAlta would provide the regulatory flexibility to ensure that customers receive the benefits of the unbilled revenues in a manner that ensures the continued stability of earnings and the financial integrity of TransAlta.

1.16A **TransAlta Utilities Corporation**
RE90089 / 900146 2510 6 3

B Complaint by Ben R. Plumer alleging unfair billing respecting the Midway Motel.

C Application abandoned due to lack of response from Complainant.

1.17A **TransAlta Utilities Corporation**
RE91024 / 910089 2050 6 2

B For approval to change existing rates, tolls and charges for electric light, power or energy furnished to its customers in Alberta for the test years 1991 and 1992.

C1 General

(a) Interim Order C91024 dated June 6, 1991 approved an interim refundable across-the-board rate increase of 7.15%.

(b) In the Phase I Decision E91093 dated December 16, 1991, the Board determined TransAlta's Rate Base, Fair Return and Revenue Requirement for each of the Test years 1991 and 1992. A summary of the Board's findings respecting certain significant issues addressed in this Decision follows.

(c) Phase 2 proceedings were in process at year end.

C2 Sheerness Unit 2

TransAlta proposed to include the costs associated with its 50% share of Sheerness Unit 2 in Rate Base in 1992. Sheerness Unit 2 is the second unit of two generating units constructed jointly by

TransAlta and Alberta Power Limited at the Sheerness station and has a total capacity of 383 MW. The Board found that there would be little, if any, AIS surplus load carrying capability in 1992 before the addition of Sheerness 2 and that the appropriate timing for the addition of the unit would be in 1992 in order to continue to maintain reliability of service. The Board considered it inappropriate to phase-in Sheerness 2 in 1992 because of TransAlta's concerns with respect to financial integrity and the modest reduction in 1992 rates. Therefore, the Board included the Sheerness 2 unit with associated coal rights and leases and transmission assets in 1992 rate base additions.

The Board considered for Sheerness 2 that a semi-annually compounded AFUDC rate was appropriate because it approximates an effective AFUDC rate weighted by the sources of capital at their effective compounding rates.

C3 Corporate Services Additions

The Board reduced both computer equipment additions to rate base and expenditures by $4.0 million for each test year because the Board considered that TransAlta may exercise a degree of discretion regarding the timing of certain computer additions.

C4 Depreciation

The Board accepted TransAlta's forecast for depreciation expense for both 1991 and 1992.

C5 Total Rate Base

TransAlta's requested rate base was $3,199.2 million in 1991 and $3,451.1 million for 1992. The Board approved amounts were $3,188.4 million in 1991 and $3,423.0 in 1992.

C6 Notes Payable Rates

The Board reduced the average rate for notes payable for 1991 to 10.44% from 11.625% and for 1992 to 9.315% from 10.5% because of a reduction of the chartered banks' prime rate. TransAlta based its forecast for notes payable interest expense on prevailing prime bank interest rates or five year term deposits.

C7 Equity Issue

The Board accepted TransAlta's forecast to increase its level of common equity in its capital structure relative to debt in order to restore coverage ratios. However, the Board determined that the $125 million equity issue would be considered to be issued in 1992 because given the evidence presented it was apparent that TransAlta would not complete its equity issue in 1991.

C8 Return on Equity

TransAlta requested a return on equity of 14.25% for each test year. The Board considered that returns of 13.5% for 1991 and 13.25% for 1992 were commensurate with returns being earned by enterprises of similar risk and were sufficient for the maintenance of a satisfactory credit rating.

C9 1992 Forecast Inflation Factor

The Board reduced TransAlta's 1992 forecast inflation factor of 4.0% for both labour and non-labour expenses to 3.5% based on the evidence of TransAlta's rate of return witness, Dr. Evans.

C10Software Development

The Board reduced TransAlta's forecast development costs by $719,000 in 1991 and $755,000 in 1992 to reflect a more levelled approach to enhancement expenditures in the interest of rate stability.

C11Income Tax Methodology

TransAlta proposed to account for income taxes using the normalized-all taxes paid (NATP) methodology for Federal and upstream Provincial taxes and the normalized deferred tax (NDT) methodology for the downstream portion of provincial taxes. The Board found that because substantially all Federal income taxes are rebated, the NATP method continues to be appropriate for the calculation of Federal income taxes. However, the Board considered that the flow-through income tax method should be used to calculate Provincial taxes because it would be inappropriate to approve a component of revenue requirement which is greater than it is required to be at that time.

C12Revenue Requirement

The Board approved a revenue requirement of $1,156.5 million compared to a requested revenue requirement of $1,204.6 million for 1991 and $1,270.7 million compared to a requested revenue requirement of $1,320.2 million for 1992.

1.18A **TransAlta Utilities Corporation**
RE91045 / 910089 2050 6 3

B Application dated July 22, 1991 for approval of certain time-of-use rates on an optional and final basis.

C By Order E91060 dated July 31, 1991 the Board approved the following time-of-use rates. These included certain Large General Service Time-of-Use Rate (Rate 760) and Large General Service Time-of-Use Off Peak Rate (Rate 770), both to be made available from August 1, 1991, and Residential Time-of-Use Rate (Rate 170), TransAlta Farm Time-of-Use Rate (Rate 370), and REA Farm Time-of-Use Rate (Rate 390), all to be made available from November 1, 1991.

The Board noted that these time-of-use rates are options for interested TransAlta customers. The Board found that it was appropriate that these time-of-use rates be subject to the interim rate rider and whatever EEMA Flow Through Rider was in place from time to time.

The Board considered that these time-of-use rates should be final rates because customer behaviour patterns would be influenced by the rate level and structure of time-of-use rates and after-the-fact adjustments to these time-of-use rates would be inappropriate.

The Board also found that applications of this nature, for a change in rates between rate hearings and approval of such changes on a final basis, should not be regarded as the "norm". Such applications would only be considered if special circumstances warrant it and for other reasons appearing to the Board to be sufficient.

1.19A **TransAlta Utilities Corporation**
RE91085 / 910089 2050 6 4

B Application by the City of Calgary for a rehearing of part of the 1991/1992 Phase I General Rate Application.

C In process at year end.

1.20A **TransAlta Utilities Corporation**
RE91086 / 910089 2050 6 5

B Application for approval of interim rates.

C In process at year end.

Section 2: Electric Energy Marketing Act Proceedings

Data reported in order of registration number.

2.1 A **Edmonton Power**
RE90029 / E3.16.3/91

B To set the price at which EP would sell electric energy to the Alberta Energy Marketing Agency (EEMA) in 1991 pursuant to the Electric Energy Marketing Act.

C Order E91003 dated January 2, 1991 amended Order E90088. The Public Utilities Board received a filing dated June 1, 1990 in which Edmonton Power filed its forecast costs of supplying electric energy to be sold to EEMA during the year 1991. Order E90088 issued December 31, 1990 set these prices. Subsequently, the Board noted a clerical error in the residential demand shown in Schedule "A" attached to Order E90088. Amending Order E91003 was issued with an amended Schedule "A" which corrected the residential demand to 277,300 kW from the 273,300 kW shown incorrectly in Order E90088.

2.2 A **Alberta Power Limited / Edmonton Power / TransAlta Utilities Corporation**
RE90031 / RE90029 / RE90028 E3.16.3/91 / E3.6.3/91 / E3.5.3/91

B Determining and fixing the Applicants' and Intervenors' costs arising from the 1991 EEMA Forecast Proceeding.

C In Order E91039 dated June 26, 1991, the Board determined that the allowed external costs of Alberta Power, EP and TransAlta were $27,374.56. The Applicants had claimed a total amount for fees and disbursements of $27,389.56. The Board determined that the Applicants should pay Intervenor costs of $88,022.41. The Intervenors had claimed a total amount for fees and disbursements of $91,497.40.

2.3 A **Alberta Power Limited / Edmonton Power / TransAlta Utilities Corporation**
RE90039 / E3.6.5/89 / E3.5.5/89 / E3.16.5/89

B Determining and fixing the Applicants' and Intervenors' costs arising from the 1989 EEMA Adjustment Proceeding.

C In Order E91038 dated June 26, 1991, the Board determined that the allowed external costs of Alberta Power, EP and TransAlta were $109,626.01. The Applicants had claimed a total amount for fees and disbursements of $118,459.21. The Board determined that the Applicants should pay Intervenor costs of $84,650.14. The Intervenors had claimed a total amount for fees and disbursements of $85,209.20.

2.4 A **TransAlta Utilities Corporation**
RE90052/900005 2090 6 2

B Determining and fixing the Applicant, Intervenor and Respondent costs arising from TransAlta's application, dated September 17, 1990, for an EEMA Flow-through Rider.

C In Decision E91032, dated June 12, 1991, the Board fixed and approved for payment Applicant, Intervenor and Respondent costs of $114,560.84. The interested parties had submitted cost claims of $116,092.67.

2.5 A **Alberta Power Limited**
RE91010 / 910031 2090 5 2

B For approval of an EEMA flow-through rate rider to adjust the EEMA transfer payment to 1991 levels.

C In Decision E91017 dated March 20, 1991 the Board approved Alberta Power's request for an EEMA flow-through rider effective April 1, 1991. On average the rider would collect an additional 4.03% from customers for a one year period.

2.6 A **Alberta Power Limited / Edmonton Power / TransAlta Utilities Corporation**
RE91030 / RE91031 / RE91032 / RE91033 / 910077 2615 1000 2 / 910091 2605 5 2 / 910091 2605 16 2/ 910091 2605 6 2

B To adjust the price at which APL, EP and TransAlta sold electric energy to the Alberta Electric Energy Marketing Agency (EEMA) in 1990, and to determine the price or pricing formula for which APL, EP and TransAlta would sell electric energy to EEMA in 1992.

C1 General
In Decision E91074 dated December 13, 1991, the Board set out the basis for determining the cost of electric energy sold to EEMA during 1990 by each of the three utilities, and the basis for determining the the cost of electric energy to be sold to EEMA during 1992 by each of the utilities.

C2 Total Utility Cost

(a) APL
APL was directed to incorporate in its 1992 forecast filing any determinations made in Decision E91095 in respect of the 1991 test year which impacted the 1992 total utility costs. APL was also directed to update its 1992 forecast filing per APL's November 8, 1991 updated 1992 forecast except to use TransAlta's allowed rate of return for 1992. The Board rejected APL's proposal to allocate fixed Operating and Maintenance (O&M) costs from Sheerness between Plant Held for Future Use (PHFFU) and Owners on the basis of the ratio of additional export GWhs produced from all Alberta Interconnected System (AIS) units to total GWhs produced by the excluded unit. The Board affirmed the existing allocation based on the contribution margins for PHFFU and Owners. The Board approved the inclusion of the demand and energy of the load from the Rainbow Lake Gas Plant in the calculation of demand and energy at the interface. The Board also approved the inclusion of a fuel cost for the Rainbow Lake Generating Station equivalent to the difference in revenues collected from Husky under Rate 36 and the revenues that would be collected had the Rainbow Lake Gas Plant been served under Industrial Rate 31. This EEMA treatment was approved for 1992 onward provided that Husky invoices APL for the value of the gas provided to APL in the amount equal to the difference between the Rate 36 and Rate 31 revenues.

(b) EP
The Board allowed the transfer of additional land to rate base in respect of Genesee 2 in the amount of $2,290,535 together with its associated Allowance For Funds Used During Construc-

tion (AFUDC). EP had requested the transfer of $3,952,227 in additional land costs to rate base together with associated AFUDC of approximately $11,000,000. The Board rejected EP's proposal to allocate O&M costs from Genesee 2 between PHFFU and Owner on the basis of the ratio of additional export GWhs produced from all AIS units to total GWhs produced by the excluded unit. The Board affirmed the existing allocation based on the contribution margins for PHFFU and Owners. The Board rejected EP's proposal to exclude fixed fuel and fixed property taxes from the Genesee 2 operating benefits calculation for 1989 and 1990. The Board found that EP's proposal was inconsistent in that EP proposed to include fixed O&M costs in the calculation. The Board considered it appropriate for the Owner and future customers to share in the fixed fuel and property tax costs while Genesee 2 was operated as an excluded unit. The Board reduced EP's proposed three month coal supply for Genesee 2 to two months because EP's estimate of the time to establish emergency coal supplies, in the event of a shut down of the drag line at the Genesee coal mine, was excessive. The Board considered it appropriate for EP to incorporate the effects of collecting and paying GST on all items included in Necessary Working Capital (NWC). EP agreed at the hearing to incorporate such effects. The Board accepted EP's actual capital structure for 1990 and proposed capital structure for 1992. The Board considered that, if in future, EP's equity ratio exceeds 30%, then a deemed equity ratio of 30% should be used for EEMA purposes. The Board considered that limiting EP's equity ratio to 30% was appropriate because the Board considered that EP's continually growing equity component of its capital structure could cause EP's composite cost of capital to exceed that of APL and TransAlta. The Board considered that the 30% limit on equity was appropriate until evidence respecting the optimal capital structure for EP was submitted. The Board continued the practice of using the average allowed rate of return on equity awarded to APL and TransAlta for EP in 1990. For 1992 EP was directed to use the rate of return awarded TransAlta. The Board considered this treatment to be a practical way of determining a rate of return for EP in the absence of a detailed rate of return study. The Board reduced EP's proposed 1992 natural gas fuel costs from $1.24 per GJ to $1.20 per GJ because the Board considered that, as a transportation customer, EP should be able to obtain a more favorable natural gas cost than the winter gas cost available to NUL's sales customers.

(c) TransAlta

TransAlta was directed to incorporate in its 1992 forecast filing the determinations made in Decision E91093 in respect of the 1992 test year.

(d) All Utilities

The Board found that compounding of AFUDC on a semi-annual basis was appropriate because a semi-annual compounding period approximated the reality of the timing of financing costs arising from the non-cash nature of AFUDC earnings. The Board approved semi-annual compounding for AFUDC on a going forward basis from 1992 onward. The Board found that O&M expenses, for NWC purposes, should be adjusted to reflect the expenses that would have been incurred if excluded units had not operated so that current customers bore the full costs that would have existed if only rate based units had operated. The Board considered that the second order effect on gross operating benefits of the NWC adjustment was relatively insignificant and could be ignored. The Board considered that the mid-year balance of the Hearing Costs Reserve Account should be included in no-cost capital for 1990 and 1992 because of the materiality of the balances. The Board considered that the mid-year amounts should be calculated excluding any Board assessments as these amounts are included separately in the revenue requirement.

C3 Classification to Demand and Energy

The Board considered that costs relating to ash lagoons should be classified to energy because ash lagoons were sized to accommodate the ash slurry output of a generating plant over a number of years. The Board considered that gas demand charges should be classified to energy because such costs were analogous to fixed fuel costs for coal units, which are classified to energy. The Board considered that revenue from export economy energy sales should be classified to energy and demand on the following basis. Revenue equal to fuel costs and incremental O&M costs are to be classified to energy, and all

revenues above such costs are to be classified to demand. Such treatment reflects equitable sharing of net export benefits between demand and energy. The Board was not persuaded to alter its existing classification to demand and energy of circulating water systems, general plant facilities, generation integration transmission facilities, and hydroelectric plant.

C4 Allocation of Production Costs to Consumer Groups

The Board approved the use of AIS provincial demands and energy to allocate production costs into the agency by consumer group for the years 1992 onward. The Board found that, in the absence of contractual arrangements respecting reserve sharing and wheeling, AIS demands were more appropriate than individual utility demands.

C5 Production Demand Allocator

The Board was not persuaded to alter the current 3W(50%)/9NW(50%) production demand allocator.

C6 Allocation of Transmission Costs To Consumer Groups

The Board was not persuaded to eliminate the allocation of transmission costs to voltage levels as proposed by APL. The Board found the use of four voltage levels by EP, instead of the seven previously used, was appropriate because it provided a consistent treatment to all utilities. The Board considered that the use of four voltage levels for transmission demand allocation provided the necessary flexibility to apply the proper transmission demand allocator at each voltage level to capture the essence of cost causation. The Board approved the use of AIS provincial demands for allocating high voltage transmission and high voltage substation costs, by consumer group, into the agency because the high voltage system is generally subject to one system planning. The Board approved the use of individual utility demands for allocating low voltage transmission and low voltage substation costs, by consumer group, into the agency because the low voltage system may be significantly influenced by the individual utility demands by consumer group. The Board was not persuaded to approve a different demand allocator for transmission costs from that used for production costs until further studies had been submitted indicating such as appropriate. The Board considered that all interruptibles for which transmission facilities are planned should be included in the determination of the transmission demand allocator used to allocate costs.

C7 Demand At The Interface

The Board considered that a composite price or pricing formula should be set by consumer group for each utility at the pooling interface based upon a composite of each utility's production unit cost and transmission unit cost by voltage level in order to properly reflect the differing proportion of interruptibles by consumer group for each utility. Accordingly, the Board approved the method of determining the utilities' demands at the pooling interface based on cost weighted production and transmission demands, as proposed by APL.

C8 Utility Refilings

On December 31, 1991, the Board issued Order E91100 setting the price for which APL would sell energy to EEMA in 1992; Order E91101 setting the price for which EP would sell energy to EEMA in 1992; and Order E91102 setting the price at which TransAlta would sell energy to EEMA in 1992. The Board also issued Order E91103 dated December 31, 1991 adjusting the price for energy sold to EEMA by the three utilities in 1990.

Section 3: Water Utilities

Data reported in groups arranged alphabetically according to the name of the regulated utility to which the application refers. Individual applications within each group are then arranged in order of registration number.

3.1 A **Acheson Park Water Corporation**
RE89026 / 880005 2050 318 2

B For approval of a change in rates and terms and conditions of service for the 1989 and 1990 test years.

C In process at year end.

3.2 A **Acheson Park Water Corporation**
RE91093 / 910137 2050 318 2

B For approval of a change in rates for the 1991 and 1992 test years.

C In process at year end.

3.3 A **Bearspaw Aqua Ltd.**
RE91059 / 910112 2090 307 2

B For approval of the Board to fix rates and charges to be imposed and further to increase the rates and charges currently set by contract for the supply of water.

C In abeyance at year end at the request of the applicant.

Section 4: Natural Gas Utilities

Data reported in groups arranged alphabetically according to the name of the regulated utility to which the application refers. Individual applications within each group are then arranged in order of registration number.

4.1 A **Bonnyville Gas Company Limited**
RE91081 / 910128 2090 555 2

B For an increase in its Gas Cost Recovery Rate (GCRR) effective January 1, 1992.

C In Decision E91096 dated December 9, 1991, the Board approved an increase in the GCRR from $0.031/MCF as approved in Decision E90095 dated December 28, 1990 to $0.053/MCF effective for all natural gas consumption on and after January 1, 1992 based on actual or estimated meter readings. Bonnyville had experienced demand for natural gas in excess of its production capacity in the winter of 1990/91, which required it to purchase additional gas supplies in order to meet customer requirements. This necessity to purchase gas was not forecast in the previous GCRR hearing, and an under-recovery of gas costs of $19,468 was forecast as at December 31, 1991. The approved GCRR reflects the collection of the 1990/91 gas cost under-recovery and the 1992 forecast gas costs over 1992 forecast sales volumes.

4.2 A **Bonnyville Gas Company Limited**
RE91087 / 910132 2050 555 2

B For approval of a change in the rates, charges or tolls for natural gas service for the 1991/92 test years.

C In process at year end.

4.3 A **Canadian Western Natural Gas Company Limited**
RC89052 / E4.7.35-89B

B For approval of a change in the rates, charges or tolls for natural gas service, for the 1989, 1990 and 1991 test years.

C1 General

(a) Phase 1 proceedings were concluded in 1990, with the issuance of Phase 1 Decision C90026.

(b) Two Phase 2 orders were issued. Decision C91012 dated March 28, 1991, approved a set of rate schedules effective April 1, 1991 through December 31, 1991 in which the base rates were lowered to minimize the GST charged to CWNG's customers while reflecting directions in Order C90032 regarding CWNG's unbilled revenues and 1989 overcollections. A second set of approved rates, to be effective January 1, 1992, was set based on the annualized 1991 test year's revenue requirement of $379,909,000.

(c) Decision C91013 dated May 10, 1991 approved Natural Gas Sales Service Regulations and dealt with transportation service matters.

(d) Order C91059 dated December 20, 1991 fixed applicant and intervenor costs relating to the Phase 2 proceedings. In general, the Board found that the cost claims were consistent with the value of assistance provided to the Board and allowed all costs consistent with the Scale of Costs. In total, the Board approved intervenors' costs in the amount of $196,756.54 and applicant external costs in the amount of $31,695.16 for a total of $228,451.70. The Board instructed CWNG to pay the allowed costs and to record the costs in the hearing reserve account approved in Decision C90026.

C2 Cost of Service Study Methodology

The Board generally accepted CWNG's 1991 forecast cost of service study (COS) including CWNG's: (a) use of "Modified Seaboard" method of allocating transmission and related costs between commodity (25%) and demand

(75%), (b) distribution of meter expenses using a weighted customer study, (c) allocation of expenses related to credit and collection and uncollectible accounts to Customer, Commodity and Demand on the basis of all costs without gas supply, (d) allocation of 100% of its underground storage expenses to demand, and (e) charging customers the same percentage for unaccounted for gas whether served from transmission or distribution systems.

C3 Rates to be Effective January 1, 1992

The Board found the range of revenue to cost ratios of 95% to 105%, which CWNG used in designing its rates, to be appropriate considering the size of the adjustments in rate levels proposed. The effects of the annualized 1991 rates that the Board approved to be effective commencing January 1, 1992, are outlined below:

(a) Rate 1 - General Service Rate (Includes Residential)

The Board approved a Rate 1 fixed charge of $11.00 per month and an energy charge of $0.550/GJ resulting in a 9.8% increase excluding gas costs (4.3% including forecast gas costs) in average Rate 1 billings and a revenue/cost ratio of 99.3% for the class.

(b) Rate 2 - Optional General Service - Large Use Rate

The Board approved a Rate 2 fixed charge of $235 per month and energy charge of $0.550/GJ, with the transition point between Rates 1 and 2 maintained at about 6200 GJ per year. Approval resulted in a 0.9% decrease (excluding gas costs) in average Rate 2 billings and a revenue/cost ratio of 102.9% for the class.

(c) Rate 3 - Optional General Service - High Load Factor

The Board approved a 6.4% decrease (excluding gas costs) in average Rate 3 billings resulting in a revenue/cost ratio of 105% for the class. The transition point between Rates 2 and 3 occurs at a load factor of approximately 38%. The Board also approved CWNG's proposal to bill Rate 3 customers based on 24 hour demand rather than on 12 hour demand necessitating an increase to a minimum billing demand of 50 GJ.

(d) Other Rates

The Board approved a 7.6% increase (excluding gas costs) in average billings for irrigation customers (Rate 5). The Board approved a 10.4% decrease (excluding gas costs) in average Gas Alberta billings. The Board approved an 11.2% decrease in Alberta Sugar Company's rates. The Board approved a 1.7% decrease in Cominco's rates.

(e) Transportation Rates

The Board approved a 12.7% decrease in long-term transportation rates (Rates 10, 20 and 30) resulting in a revenue/cost ratio of 104.1%. The Board approved short-term transportation rates which were derived from long-term rates using the multipliers approved by the Board in Report E86110 dated December 30, 1986. The multipliers are 1.33x for a one year contract term, 1.26x for a two year term and 1.21x for a three year term. The Board approved Rates 12 and 13 (for deliveries to industrial end-users) designed using the "peeled" methodology consistent with that approved in Order E89101 dated October 25, 1989.

(f) Buy Sell Rates

The Board approved Rate 40 and Rate 41 (which was identical to that approved on an interim basis in Decision E89101 dated October 25, 1989). The Board was not convinced that there was a concern of a migration of customers from sales to Buy/Sell service.

C4 Rates Effective April 1 to December 31, 1991

In Order C90032 concerning Phase I of CWNG's General Rate Application for the years 1989/90/91, the Board determined that CWNG had collected a revenue surplus of $6,903,000. The Board directed CWNG to propose a method to distribute the surplus, and its unbilled revenues totalling $12,498,000, to its customers. In Decision C91012, the Board approved CWNG's proposal to reduce each rate group's base energy charges on the annualized 1991 rates to reflect the amount of the unbilled revenues and cumulative surplus allocated to that rate group. CWNG considered that approach provided the greatest certainty that the GST would only be charged on customers' net billings. Under this approach there is no reconciliation: if the period from April 1, to December 31, 1991 is warmer than normal CWNG will collect base revenues which are lower by less than the amount of the unbilled revenues and the cumulative surplus and if the period is colder than normal CWNG will collect base revenues which are lower by a

greater amount than the unbilled revenues and the cumulative surplus.

C5 Changes To CWNG's Natural Gas Sales Service Regulations

The Board allowed CWNG to increase its reconnection fee from $25.00 to $45.00 and approved clauses to enable use of customer telephone lines for automatic meter reading (AMR) and to require contributions of $50.00 for customer requested installation of AMR outside CWNG's planned installation program.

C6 Request For The Provision Of Depths Of Utility Facilities

The Board denied the request by the Alberta Roadbuilders Association that CWNG be required to provide the depth of any new utility installations. The Board judged that the benefits from providing surveyed depths would not justify the costs.

C7 Contract Renewal Rights For Short-Term Transporters

The Board rejected transporters' proposals of automatic renewal of short-term transportation contracts. The Board found that automatic short-term contract renewal without responsibility for incremental common facility costs would discriminate against core customers who would pay for any facilities, installed to meet transporters' capacity requirements, which were not used.

C8 Contract Renewal Rights For Long-Term Transportation Customers

The Board considered that customers who have contributed to the system over the long-term should have the right to renew and continue to use the portions of the system that they have committed to. The Board accepted that 20 year firm service contract customers should be allowed to continue service indefinitely using one year contract extensions, provided that 3 years notice of each year's extension was provided to the utility.

C9 Complaint by TransCanada Pipelines Limited (TCPL)

The Board agreed with TCPL that the cost of the compressors required to allow transport of gas on the Southern Extension of CWNG's Eastline should be considered as system costs instead of being paid only by the transporters on the Southern Extension.

C10 The Banff Transmission Line Looping As A System Improvement

The Board found that the Banff Transmission Line Looping should be treated as a system improvement with no specific facility charges required.

C11 CWNG/NUL Imbalance Calculation and Settlement Provisions

The Board rejected transporters' proposals which called for changes in imbalance calculation and settlement provisions, to reduce penalties to transporters. The Board found that current imbalance provisions already gave transporters a two-way benefit: (1) no charges for daily imbalances, and (2) no charges for monthly net imbalances up to a limit of + or - 5%.

C12 CWNG/NUL Transportation Contract Durations

The Board rejected transporters' proposals for firm transportation service for durations between 4 and 20 years (1, 2, 3 and 20 year contracts were already available) given the uncertainty of CWNG/NUL capacity requirement forecasts beyond a three year period.

4.4 A **Canadian Western Natural Gas Company Limited**

RE91008 / 910029 2090 7 2

B For approval of a change in its summer gas cost recovery rate (GCRR) to $1.221 effective April 1, 1991, and to reconcile its 1990 summer period gas costs

C In Interim Order C91014 dated March 31, 1991, the Board approved the 1991 summer GCRR of $1.221/GJ requested by CWNG, stating that the calculations and forecasts used to derive the GCRR were reasonable. The approved GCRR was $.021/GJ higher than the 1990 summer GCRR.

In Order C90009 dated March 12, 1990, the Board had postponed consideration of the 1989 reconciliation of summer season gas costs because the price of a "significant portion" of the gas supplied to CWNG under long-term contracts subject to annual price redetermination was not then settled. In Order C91014, with prices for over 88% of the gas volumes supplied under such contracts settled for 1989 and 1990, the Board found that CWNG's 1989 and 1990 summer season gas cost reconciliations were satisfactorily represented.

4.5 A **Canadian Western Natural Gas Company Limited**
RC91027 / 910107 2090 7 2
B For approval of a change in Rate Rider "A" relating to the Municipality of Crowsnest Pass to include natural gas transportation customers.
C Approved / Order C91047 dated October 30, 1991.

4.6 A **Canadian Western Natural Gas Company Limited**
RC91035 / 910124 2090 7 2
B For approval of a change in revenue tax rates relating to the Town of Banff.
C Approved / Order C91050 dated November 27, 1991.

4.7 A **Canadian Western Natural Gas Company Limited**
RC91038 / 910125 2090 7 2
B For approval of a change in Rate Rider "A" relating to the Town of Crossfield to include natural gas transportation customers.
C Approved / Order C91055 dated November 27, 1991.

4.8 A **Canadian Western Natural Gas Company Limited**
RC91044 / RC91045 / 910130 2090 7 2 / 910131 2090 7 2
B For approval of a change in Rate Rider "A" relating to the Village of Linden and the Town of Fort Macleod to include natural gas transportation customers
C Approved / Order C91058 dated December 13, 1991.

4.9 A **Canadian Western Natural Gas Company Limited**
RE90092 / 900081 2090 7 2 / RE91026 / E4.7.35-89 R.V.
B The City of Calgary applied for an Order of the Board respecting a change in the methodology of accounting for provincial income taxes approved in Decision C91023 dated July 12, 1991. CWNG applied for a review and variance of Decision C91013 dated May 10, 1991 which approved rates, tolls and charges designed to recover the utility revenue requirement approved in Decision C90026 dated July 27, 1990.
C Order C91042 dated August 23, 1991 approved rate refund riders respecting the methodology of accounting for provincial income taxes in the utility revenue requirement as filed by CWNG. The Board also approved CWNG's application for a review and variance by approving rate riders for the period September 1, 1991 to December 31, 1991 to collect the cost of CWNG's Southern Extension Compressor.

4.10A **Canadian Western Natural Gas Company Limited**
RE90094 / 900039 2090 7 2
B For approval of changes to the General Conditions applying to all rates as a result of the application of municipal franchise taxes to transportation customers.
C Order C91018 dated April 30, 1991 approved the application. Full written reasons were pending at year end.

4.11A **Canadian Western Natural Gas Company Limited**
RE91048 / 910038 2230 7 2
B For an order of the Board approving the purposes of and authorizing the issue of 800,000 Series P Preferred Shares for $20,000,000 to Canadian Utilities Limited.
C Order E91063 dated August 15, 1991, approved the application.

4.12A **Canadian Western Natural Gas Company Limited**
RE91051 / 910105 2090 7 2
B For approval of a Rate Reduction Rider "F" of $0.131/GJ to adjust the summer period Gas Cost Recovery Rate (GCRR), effective on all consumption on and after August 15, 1991 until October 15, 1991, inclusive. This reduction resulted from lower gas costs for both the short term/flexible gas and export gas.
C Order E91062 dated August 15, 1991, approved CWNG's application stating that it was beneficial for CWNG's rates to reflect savings on the gas cost recovery component in a timely fashion. The application also minimized the balance in CWNG's DGA account. The

creation of Rider "F" would expedite future changes to the GCRR when forecasts differ from actual rates.

4.13A **Canadian Western Natural Gas Company Limited**
RE91066 / 910116 2090 7 2

B For a change in its Rider "F" to reflect its winter gas cost recovery rate (GCRR), effective November 1, 1991, and for a change in its Rider "D" for collection of unaccounted for gas (UFG) costs, effective January 1, 1992.

C In Order C91044 dated October 23, 1991, the Board approved CWNG's Rider "F" which set the 1991/92 winter GCRR of $1.497/GJ based on a cumulative deferred balance of $1,543,000 and forecast 1991/92 winter gas costs of $94,373,000. The Board also approved Rider "D" for UFG collections of 1.1%, based on CWNG's three year rolling average UFG experience.

4.14A **Canadian Western Natural Gas Company Limited**
RE91090 / 910034 2230 7 2

B For an order of the Board approving the purposes of and authorizing the issue of a 9.92% Debenture 1991 Series in the principal amount of $15,000,000 to Canadian Utilities Limited.

C Order E91106 dated December 19, 1991, approved the application.

4.15A **Canadian Western Natural Gas Company Limited / Northwestern Utilities Limited**
RE91012 / 910033 2090 7 2 / 910033 2090 14 2

B For approval of a deemed value of gas for municipal revenue tax purposes.

C Order C91018 dated April 30, 1991 determined a deemed value for CWNG and Order C91019 determined a deemed value for NUL. Full written reasons were pending at year end.

4.16A **Centra Gas Alberta Inc.**
RE89102 / E4.15.35-45B

B For approval of changes in the existing rates, tolls or charges for natural gas service furnished to its customers in Alberta for the 1989 and 1990 test years.

C1 General

(a) Phase 1 Decision E90057 dated October 10, 1990 as amended by E90073, determined Centra's (formerly ICG Utilities (Alberta) Ltd.) rate base, fair return and revenue requirement for the 1989 and 1990 test years.

(b) Order E91070 dated December 23, 1991 determined applicant and intervenor costs relating to the Phase 1 proceedings, as well as the Phase 1 review and variance proceedings and the 1991 GCCR proceedings. The Board considered that the intervention mounted by the Urban Municipalities (UM), the Municipal and Gas Co-op Intervenors, the Energy Users Association of Alberta (EUAA), and High Level Forest Products (HLFP) was effective and very useful to the Board in its examination and testing of the three proceedings. Accordingly, the Board approved costs of $13,193.73, $13,322.83 and $2290.30 for the UM, MGCI and EUAA respectively. HLFP claimed costs of $1,671.14. The Board noted that some of the costs claimed by HLFP did not conform to the Board's scale of costs and reduced HLFP's costs in accordance with the scale of costs to $1,479.14. The Board approved external costs as claimed by the Company in the amount of $29,530.81

(c) Phase 2 Decision E91031 dated July 28, 1991 set out the Board's findings with respect to rate design. Details are set out below.

(d) Order E91059 dated August 16, 1991 approved final rates designed in accordance with Phase 2 Decision E91031.

(e) Order E91040 dated December 23, 1991 determined applicant and intervenor costs relating to the Phase 2 proceedings in the amount of $141,826.78. The Board considered that the intervention mounted by the Urban Municipalities (UM), the Municipal and Gas Co-op Intervenors, the Energy Users Association of Alberta (EUAA), and High Level Forest Products (HLFP) was effective and very useful to the Board in its examination and testing of the Phase 2 proceedings. Accordingly, the Board approved costs of $28,537.99, $24,491.48 and $1927.74 for the UM, MGCI and EUAA respectively. HLFP claimed costs of $32,053.96. The Board noted

that some of the costs claimed by HLFP did not conform to the Board's scale of costs and reduced HLFP's costs in accordance with the scale of costs to $28,193.71. The Company claimed costs of $62,512.09. The Board noted that some of the costs claimed by the Company did not conform to the Board's scale of costs and reduced the Company's costs in accordance with the scale of costs to $58,675.86.

C2 Rate Design

The Board accepted the Company's proposal to adopt a postage stamp rate structure because the system was effectively interconnected for a major portion of the area served; the system had similar design and engineering standards so that the quality and reliability of service rendered was reasonably uniform; and a comparable extension policy and practice was in place with respect to the ownership of facilities throughout the system.

The Board approved the Company's proposal to establish an Optional Irrigation Pumping Service rate. Prior to the establishment of the irrigation rate, irrigation customers received service under the Small General Service (SGS) rate. The new irrigation rate was designed taking into consideration that irrigation customers were on the system during the irrigation season only, and not at the time of the system peak.

The Board approved all rates as proposed by the Company, with the exception of the SGS rate. The Board expressed concern that the proposed SGS rate structure constituted an inappropriate rate shock to a large number of Centra's SGS customers. The Board indicated that it was prepared to accept a step rate as a means of reducing the impact of the rate restructuring while still providing a postage stamp rate for the SGS customer class. Centra was directed to file a step rate proposal that generated the same amount of revenue as the Company's proposed rate and addressed the Board's concerns.

C3 Refiled Rates

The Company filed a step rate proposal as directed by the Board in Decision E91031. Centra did not recommend the adoption of a step rate notwithstanding the Board's reasons outlined in Decision E91031. Instead Centra proposed a new SGS rate with a reduced fixed charge from that originally proposed in the Company's Phase 2 evidence. The Board accepted the Company's new SGS proposal because it addressed the Board's concerns that the original proposal would constitute an inappropriate rate shock to many SGS customers.

The Board accepted the Company's proposal to allocate the 1990 revenue surplus on the basis of the difference between existing and proposed rates to all classes except Transportation. The Board found Centra's proposal was based on the 1990 cost of service, and was just and reasonable to all classes. The Board rejected the same proposal made by the Company for refunding the 1989 revenue surplus because such an allocation of the surplus was not supported by a cost of service study. In the absence of such a study the Board found it appropriate to allocate the 1989 revenue surplus on the basis of non-gas revenues. The Board found that billing revenues, as opposed to gas consumption, were appropriate for prorating the 1989, 1990 and 1991 revenue surplus to individual customers because the refund amounts related to differences in both the commodity charge and the fixed charge.

4.17A **Centra Gas Alberta Inc.**
RE90063 / 900035 2090 15 2

B For approval to establish a Gas Cost Recovery Rate (GCRR) for 1991.

C In Order E91001 dated January 4, 1991, the Board fixed a GCRR for 1991 of $1.580/GJ. The Board noted that Centra (formerly ICG) was forecasting increases to components of its gas supply portfolio at a time when industry trends and other utilities were indicating price decreases. The Board also noted that 31% of Centra's 1991 gas volumes were represented by contracts not yet finalized as to price. The Board found that the evidence provided by the Company did not support setting the GCRR at $1.602/GJ, the level requested by the Company. The Board set the 1991 gas costs at the mid point of the Company's forecasts for 1990 and 1991, resulting in a 1991 GCRR of $1.580/GJ. The Board expressed a concern that some of the evidence filed in support of the application was

not adequate to allow for complete analysis and directed Centra to provide more detail in support of future GCRR applications. The Board also expressed a concern that a portion of Centra's actual gas costs and recoveries would not be reconciled until November of 1991, and that any under/over recovery indicated by that reconciliation would not be completely collected/refunded until December 31, 1992. The Board directed Centra to file a calendar year reconciliation of 1990 gas costs and recoveries by March 31, 1991 at which point the Board would determine if proceedings to adjust the 1991 GCRR were warranted.

4.18A **Centra Gas Alberta Inc.**
RE90068 / E4.15.35-45A RV

B For a review and variance of Decision E90057 as amended by E90073. Centra's application concerned the approved line losses based on a five year rolling average line loss; the capital additions for 1990; and, the deemed cost of debt.

C In Order E91004 dated July 18, 1991, the Board denied the Company's application with respect to line losses because the Board found no error of law or fact in its determination. The Board considered that it was entitled to use past forecasts and actuals as factors to be considered in its finding.

The Board chose not to exercise its discretion to vary E90057 as amended with respect to capital additions because the Board found the increase requested by the Company on this matter to be immaterial. The Board denied Centra's application with respect to the cost of debt because the Board found that Centra's application did not meet any of the Board's established criteria for review and variance. The Board found that circumstances had not changed since a deemed cost of debt was approved in Decision E85133 and therefore, the Board continued to find the use of the deemed cost of debt appropriate. The Board confirmed its finding that the Company's use of short term debt to finance capital additions since 1985 was inappropriate, and therefore, the Board continued to find its approved treatment of the Company's short term debt as if it were long term debt, appropriate.

4.19A **Centra Gas Alberta Inc.**
RE90096 / RE91005 / 900086 2090 15 2 / 910011 2090 15

B For approval of a change in rates relating to the Town of Athabasca and the Town of High Level because of changes in the revenue tax rates.

C Approved / Order E91022 dated April 10, 1991.

4.20A **Centra Gas Alberta Inc.**
RE91015 / 900062 2240 15 3

B For approval of the disposition of the proceeds of the sale of its Drumheller office.

C In process at year end.

4.21A **Centra Gas Alberta Inc.**
RE91040 / 910099 2050 15 2

B For approval of changes in the existing rates, tolls or charges for natural gas service to its customers in Alberta for the 1991 and 1992 test years.

C1 By Decision E91067 dated August 28, 1991, the Board approved a refundable interim rate increase effective for all consumption of natural gas on and after September 1, 1991 based on actual or estimated meter readings. The rate increase approved was forecast to recover 60% of Centra's non-gas forecast 1991 revenue deficiency ($1,338,865 of $2,231,441) and 78% of the 1992 non-gas forecast revenue deficiency ($3,366,825 of $4,303,237). Any surplus or deficiency relating to gas costs is addressed in the Gas Cost Recovery Rate proceedings through the Deferred Gas Accounting and Reconciliation mechanism. The proportionate amounts of allowed deficiencies were based on an exclusion of those untested issues in evidence filed with the GRA which had a significant impact on the revenue deficiencies forecast by Centra for the test years. Examples of such untested issues were a change in the method of temperature based sales normalization (from historical averages to exponential smoothing) and an increase in the rate of return on common equity. The Board considered the interim rate increase met the objectives of rate stability, intergenerational equity and financial integrity in a just and reasonable manner.

C2 The Phase 1 decision was pending at year end.

4.22A **Centra Gas Alberta Inc.**
RE91041 / 900035 2050 15 3

B For a reduction in its Gas Cost Recovery Rate (GCRR) effective September 1, 1991.

C By Decision E91066 dated August 28, 1991, the Board approved a reduction in the GCRR from $1.580/GJ, as approved in Decision E91001 dated January 4, 1991, to $1.269/GJ effective for all natural gas consumption on and after September 1, 1991 based on actual or estimated meter readings. Centra had experienced declining gas costs for the first part of 1991 and expected gas supply costs to remain below the GCRR for the remainder of the year. Accordingly, Centra applied to the Board early for a reduction in the GCRR rather than wait until November when it would have filed an application for a 1992 GCRR. Centra had indicated through the cross examination process that the price negotiated for gas supply was not necessarily the lowest possible price. Centra was therefore directed to file evidence at the next GCRR hearing regarding the negotiated prices for gas supply and information regarding the security of that supply.

4.23A **Centra Gas Alberta Inc.**
RE91082 / 910129 2090 15 2

B For an increase in its Gas Cost Recovery Rate (GCRR) effective January 1, 1992.

C In Decision E91097 dated December 10, 1991, the Board approved an increase in the GCRR from $1.269/GJ as approved in Decision E91066 dated August 28, 1991 to $1.330/GJ effective for all natural gas consumption on and after January 1, 1992, based on actual or estimated meter readings. The Board's previous Decision, E91066, reduced Centra's GCRR below the Company's proposed cost of gas in order to effect a refund of an overcollection of 1990 gas costs of $761,994 over the period September 1, 1991 to December 31, 1991. In this application, Centra included an additional over-recovery amount of $837,837 relating to actual unaccounted for gas experienced for the period from May, 1990 to May, 1991. The allowed GCRR reflects the refunding of this amount and 1992 forecast gas costs over 1992 forecast sales volumes. Centra requested, and was allowed, to change its DGA filing requirements from monthly to quarterly reporting. The required quarterly reports are to contain information on a monthly basis.

4.24A **Centra Gas Alberta Inc.**
RE91092 / 910136 2090 15 2

B For approval of a change in the rates relating to the Town of Pincher Creek because of a change in the revenue tax rate.

C In process at year end.

4.25A **Elk Point Gas, Ltd.**
RE91052 / 910106 2050 1004 2

B For an increase in natural gas rates, tolls and charges for natural gas service to its customers in Alberta for the 1991, 1992 and 1993 test years.

C1 By Decision E91071 dated August 30, 1991, the Board approved an interim refundable rate increase of $0.45 per Mcf effective for all consumption on and after August 1, 1991 based on actual or estimated meter readings.

C2 The Phase 1 decision was pending at year end.

4.26A **Grande Prairie Transmission Co. Ltd.**
RE91075 / 910121 2240 1005 2

B Application by Northwestern Utilities Limited on behalf of BC Gas Inc. for authorization to sell all of the common and preferred shares of Grande Prairie Transmission Co. Ltd. to Northwestern Utilities Limited.

C In Order E91072, dated October 11, 1991, the Board gave its authorization to BC Gas Inc., as owner of Grande Prairie Transmission Co. Ltd., to sell the common and preferred shares of Grande Prairie Transmission Co. Ltd. to Northwestern Utilities Limited. The application proceeded on an ex parte basis as Northwestern purchased 99.5% of Grande Prairie Transmission Co. Ltd's gas; the sole remaining customer, Gas Alberta, had no objections to the proposed sale and further considered it beneficial to its interests; and the proposed closing date for the sale of shares was October 11, 1991 which created an element of urgency.

4.27A **Northwestern Utilities Limited**
RE90067 / 900049 2090 14 2

B For approval of increases in the reconnection fee and charge for dishonored cheques contained in Schedule "A" of its Natural Gas Sales Service Regulations outside the context of a General Rate Application (GRA).

C1 Findings of the Board

In Order E91002 dated January 8, 1991, the Majority of the Board approved the proposed increases in charges on an interim basis, to be finalized if appropriate, in NUL's 1991/1992 GRA. The majority of the Board also stated they were not convinced that the application met the tests laid out in Decision E85111 dated September 30, 1985 for approval of rate changes between GRAs.

C2 Dissent of Member A. Calista Barfett

The Board should approve the proposed increases as final rates as NUL had satisfied the conditions set out in E85111 which were still a suitable guide for assessing such applications; the proposed charges reflected NUL's cost of providing the respective services; and it was inappropriate to approve charges such as those in the application, which are for specific services, on an interim basis, since the utility could not be reasonably expected to go back and recover any under recovery, or refund any over recovery, of the actual costs resulting from the interim charges.

4.28A **Northwestern Utilities Limited**
RE91001 / 910002 2050 14 2

B For approval of a change in the existing rates, tolls and charges for natural gas service furnished to its customers in Alberta for the 1991 and 1992 test years.

C1 General

(a) Interim Order E91028 dated May 1, 1991 approved interim refundable rate increases, effective May 1, 1991, pending approval of final rates. The interim rate increase approved was forecast to recover $10 million. This was only about 40% of the projected non-gas revenue shortfall of $26.4 million in 1991. Should the Board not establish NUL's revenue requirement by December 31, 1991, NUL was to have the option to request extension of the interim rates. All surplus or deficiencies related to gas costs would be addressed in the Gas Cost Recovery Rate proceedings through the Deferred Gas Accounting and Reconciliation mechanism. In approving the quantum of revenues to be recovered by interim rates, the Board considered that the amount approved met the conflicting goals of rate smoothing and reducing the possibility of a subsequent rate refund.

(b) Phase 1 Decision E91044 dated November 18, 1991, as amended by Decision E91094 dated November 22, 1991, established the rate base, fair return and revenue requirement for the test years. Details are set out below.

(c) Phase 2 proceedings were in process at year end.

C2 Additions to Gross Plant In Service

(a) Variances In Capital Addition Expenditures

The Board did not consider it appropriate to impose an across-the-board reduction in the forecast of capital expenditures based only on historical results. As for the quantum of expenditure, the Board considered the onus to be on the utility to justify individual capital expenditure forecasts. The Board directed NUL to provide explanations for significant deviations between forecast and actual capital expenditures commencing 1991.

(b) Edmonton Bare Main Replacement Program

The Board approved the expenditures as forecast but directed NUL to provide a detailed analysis of its labor costs in the "capital" and "removal" segments of the program and to identify the extent of replacement work carried out by third parties. NUL was also directed to clearly identify the amounts of contingency allowance in its capital expenditure forecasts.

(c) Supervisory Control and Data Acquisition (SCADA)

The Board reduced NUL's gross plant by $1.5 million in 1991 and $1.0 million in 1992 for the SCADA project and included the expenditures in CWIP, with full AFUDC. These costs are to be brought into rate base when the SCADA system is fully operational (in 1993).

(d) Salt Cavern Withdrawal Equipment

Plant additions respecting additional withdrawal equipment were approved inasmuch as such equipment would enhance the withdrawal capability at the caverns to meet the increases in expected peak demand. The Board considered it was unrealistic to rely on small, unmanned plants to supply gas on short-term notice during extreme winter weather conditions, as recommended by

the Industrial Gas Consumers Association of Alberta.

(e) Salt Cavern 6 & 7

The Board approved inclusion of costs incurred during 1991 and 1992 in respect of the development of two additional caverns considering NUL's evidence of anticipated increases in peak demand and supply deficiencies. Caverns No. 6 and No. 7 are expected to be placed in service in 1993/1994 and 1994/1995, respectively. The Board directed, however, that NUL provide evidence at its next GRA, of the availability of alternate supplies and steps taken to curtail peak day demand (including the extent to which interruptible load could be interrupted).

(f) Salt Cavern Common Facility Costs

The Board in E87002 allocated all common costs over the 15 probable caverns to be developed. The Board agreed with NUL's evidence that it was unlikely all fifteen probable caverns would be developed within the next 20 years and that this would distort the cost-benefit analysis of bringing future additional caverns into rate base. The Board approved NUL's proposal of bringing $1.0 million of the common facility costs from PHFFU into rate base in 1991 with the commencement of mining of Salt Cavern 6 and to bring the remaining $9.5 million into rate base in 1992.

(g) Natural Gas Vehicle (NGV) Program

To the extent Company vehicles are converted to natural gas, the Board considered it appropriate to include these costs in rate base considering the positive effect such a marketing approach would have on the NGV program. Respecting the public program, considering that there was evidence demonstrating a positive net benefit, the Board approved the related costs in rate base.

(h) Automatic Meter Reading (AMR)

The Board approved the AMR program. However, based on a variety of factors including NUL's affiliation with the supplier of the units, the Board considered a 3,000 unit inventory as being reasonable, compared to NUL's proposal for 7,500 units. The Board, accordingly, adjusted the capital expenditure to $2.0 million in 1991 and $2.2 million in 1992, with the expenditure for the 4,500 units being held in PHFFU.

(i) Computer Equipment

The Board approved NUL's expenditures as filed. In view of insufficient evidence on shared costs, the Board directed NUL to submit a complete analysis on the use of the new system to support the usage, costs and allocation of the new system amongst all users within the Canadian Utilities (CU) group.

(j) Gross Plant-in-Service Total

The Board, in total, reduced NUL's gross plant in service by $2.2 and $5.0 million in 1991 and 1992, respectively.

C3 Accumulated Depreciation And Depreciation Expenses

(a) General

NUL updated its 1985 depreciation study and recommended appropriate depreciation procedures, rates, and amortization amounts for NUL's depreciable gas plant-in-service as at December 31, 1989. NUL forecast an increase in depreciation expense of $1.6 million in 1991 and $1.7 million in 1992.

(b) Production & Gathering (P&G) Life Analysis

Certain Intervenors' submitted that time, as opposed to units produced, is a better measurement of the decrease in service value of P&G assets. The Board considered that where use of an asset can change significantly over time, and where life can reasonably be measured by the UOP method, the UOP method provides a better matching of the usefulness of P&G assets over time. With respect to pooling of P&G assets, the Board considered that this method would help stabilize the swings in the depreciation expense of individual wells resulting from differences between forecast and actual withdrawals from a field in a given year. Further, the pooled method recognizes that while withdrawals may vary from field to field, no change in depreciation expense occurs if there are no changes in the annual aggregate withdrawals. The Board therefore approved NUL's proposal as submitted.

(c) P&G Net Salvage

The Board agreed with the principle of including net salvage in calculating depreciation expenses and accepted NUL's net salvage costs. The Board calculated the negative net salvage ratio to be 25% based on the UOP method and a 37 year life to depletion, and accordingly reduced NUL's depreciation expense with respect to P&G Net Salvage by $983,000 in 1991 and $993,000 in 1992.

(d) Mass Property Life Analysis

While the Board accepted NUL's choice of Iowa curves for selection of life characteristics, the Board expressed concern that NUL had not adequately demonstrated reasons why visual curve fitting and judgment were superior to mathematical curve fitting for the ten mass property accounts in question. The Board, accordingly, directed NUL to provide reasons, at its next GRA, for the choice of a particular curve considering (a) historical life characteristics and trends, (b) physical, environmental and technological attributes affecting retired plant, (c) factors that may affect retirement of property in future.

(e) Mass Property Net Salvage

Respecting transmission mains (Account 465), the Board noted that while NUL's evidence was not conclusive, the industry average net salvage ratio of 15% was consistent with that used by and proposed by NUL for the test years. This ratio was therefore approved by the Board. For Services (Account 473), NUL proposed to increase its net salvage ratio from 50% to 100% while the Municipal Intervenors (MI) recommended 75%. The Board considered NUL did not provide conclusive evidence that experienced historical net salvage ratios are representative for the survivors in Account 473. Considering factors such as gradualism and industry averages, the Board approved a negative net salvage of 75%. For Meter Installation (Account 474), NUL proposed to increase negative net salvage from 0% to 100%. The Board considered that the 1983 to 1989 historical salvage ratios may not be representative of the average for the survivors in this account. Further, considering industry data and the desire to introduce gradualism, the Board approved a negative salvage factor of 50%.

For Distribution Mains (Account 475), NUL proposed to increase negative net salvage from 15% to 50%. Considering industry data, and further that NUL had not provided conclusive evidence that its historical salvage ratios were representative of the average survivors on Account 475, the Board approved a factor of 33%.

(f) ELG vs ALG

The Board was not persuaded by the MI's submission on the need to change the method of depreciation from ELG to ALG. The Board considered that the ELG method provides a better match of depreciation expense with the useful life of property. The Board acknowledged that under certain scenarios, ELG could result in higher depreciation accruals in initial years but the Board was not persuaded that ELG was an accelerated method of depreciation. While depreciation rates using ELG may change from year to year depending on addition/retirement of assets in a given vintage, the Board considered that the existing procedure for adjusting reserve differences greater than 5% was adequate to adjust in a timely manner any over or under collection of depreciation expenses.

(g) Total Accumulated Depreciation

In total, the Board reduced NUL's forecast depreciation expenses by $2.7 million and $5.9 million for 1991 and 1992, respectively.

C4 Necessary Working Capital (NWC)

(a) Lead/Lag vs. Balance Sheet Method

The Board considered that a lead/lag study that reflects all cash flows provides the best estimate of NWC.

(b) Income Tax Installment

The Board adjusted the amount of the income tax installment to be included in the NWC calculation for 1991 and 1992 based on the income tax liability incurred in 1990 and approved for 1991. The Board also adjusted the final income tax payment lag to 203 days from 182 days as filed by NUL.

(c) Depreciation Expense

Considering depreciation expense is earned at the same time as revenue is received, the Board approved NUL's proposal to use a lag of 39.45 days, being the lag in receipt of revenues.

(d) Financial Items

IGCAA took the position that while the utility earns common equity return on a daily basis, it pays dividends on a quarterly basis, allowing it to retain such equity over the period and earn additional return on retained earnings. The Board considered that inasmuch as each of the tests used to determine the rate of return on common equity reflects continuous compounding of cash flows, the utility's approved rate of return is the approved effective rate. Hence, any augmentation due to compounding of cash flows would result in a higher common equity return than indicated by the rate of return tests. Further,

the Board considered that because of the mid-year convention, any positive compounding in the first half of the year is considered to be exactly offset by the negative compounding in the balance of the year.

C5 Fair Return

(a) Position of the Board

The majority of the Board approved a rate of return on common equity of 13.75% for each of the test years. Inasmuch as regulation is considered a surrogate for competition, and the comparable earnings test (CET) measures the achieved return on common equity of enterprises similar in risk, the Board considered the CET, as well as other tests (the Discounted Cash Flow and Equity Risk Premium tests), to be all valid indicators of the range in or around which a fair return should fall. With respect to flotation costs, the majority considered that these are ongoing costs which should be reflected each time a common equity rate of return is approved rather than only at the time of issuing new common equity in order to provide the utility with the required financing flexibility. The majority considered that the fair return determination was more than an exercise to estimate the dollar value of another component of revenue requirement. It is seen as a signal of the regulator's assessment of the many complex and often contradictory views presented. Ultimately, judgment must be applied to balance all factors.

(b) Dissent of R.D.S. Ward

The dissenting member stated he would have awarded a rate of return of 13.375% on that portion of rate base financed by common equity. Member R.D.S. Ward took into consideration the down turn in the economy and the consequential economic hardship experienced by customers. Further, inasmuch as investors tend to purchase utility stocks when the economy is in a recession, NUL's ability to attract new capital is not impaired. Member R.D.S. Ward observed that over the years 1975 to 1990 inclusive NUL has earned, on average, 3.3% more than its allowed rate of return. Member R.D.S. Ward submitted that the performance of CU's non-utility operations may have caused the negative reaction from bond rating agencies. Further, it would have been helpful if NUL had brought forward, as a witness, a member of a bond rating service to determine what data was relied upon to cause the adverse reaction. Finally, Member R.D.S. Ward considered a flotation cost allowance of 50 basis points adequate to prevent dilution.

C6 Utility Revenue Requirement

(a) Cash O&M Expenses

The Board, upon review of Phase I costs for other major utilities, reduced NUL's forecast hearing cost of $1,000,000 to $800,000 for each of the test years to cover both Phase I and Phase 2 costs. With respect to pension costs, the Board considered NUL's assessment of the market value of its pension plan assets did not include some recent gains that would have resulted in a somewhat lower forecast of pension expense. Accordingly, the Board reduced NUL's forecast by $770,000 in 1991 and $1,100,000 in 1992, being one-half of the increases sought.

(b) Non-Cash Operating Expenses

The Board removed the unamortized software development costs from gross plant-in-service and included these in NWC, consistent with guidelines laid out in Decisions E89091 and E89095. With respect to income tax, the Board approved the use of the NATP method to calculate the federal taxes payable since a significant portion of the federal income tax continues to be rebated. With respect to provincial taxes, the Board approved the Flow-Through method. The Board also did not allow NUL to claim 1990 year-end unbilled revenues of $20.3 million as an addition to 1991 timing differences for provincial purposes, in order to harmonize the accounting and tax treatments.

C7 Utility Revenues

The Board approved the 20 year rolling average method of normalization as opposed to the 0.3 Exponentially Smoothed method proposed by NUL. The Board also accepted NUL's usage per customer forecasts.

C8 Other Matters

(a) Treatment of Deferred Transportation Revenue Account

The Board approved the inclusion of balances in the short-term firm service premium revenue deferral account as customer contributions for 1991 and 1992. This account would be discontinued in the future. The Board approved NUL's proposal to credit the authorized and unauthorized deferral account balance against the 1991 forecast

revenue shortfall and to discontinue this account. The Board also approved NUL's proposal to allocate interruptible revenues between incremental and displaced sales. The Board also approved NUL's proposal to apply the incremental interruptible revenue against the 1991 forecast revenue shortfall and those revenues resulting from the displaced sales going to shareholders. Further, the Board approved discontinuance of this account.

(b) Inter-Company Transactions
The Board directed NUL to file corporate intercompany policies at its next GRA.

4.29A **Northwestern Utilities Limited**
RE91006 / 910018 2510 14 2

B Complaint by Hartford Management & Financial Group Inc. respecting the security deposit policy and billing practices of NUL.

C Decision E91019 dated March 21, 1991 set out the Board's findings respecting this complaint. Hartford had commenced operating the Red Deer Inn in July of 1990, although ownership of the Inn remained with another party. Since Hartford had had no previous accounts with NUL, the company's policy is to assess a security deposit, or its alternative, a letter of guarantee or surety bond. However, Hartford claimed that they had not been advised of the deposit requirement at the time of the service request. Since NUL generally takes such service requests by telephone, there were no written records substantiating NUL's assertion that Hartford would have been advised of the deposit requirement. The picture was further muddied by the fact that NUL had obtained a "letter of guarantee" from the apparent owners of the Red Deer Inn. Hartford claimed that this letter relieved them from the obligation of providing a security deposit. While NUL asserted that it is company policy to only obtain letters of guarantee from financial institutions, no correspondence or written documentation exists to that effect.

While the Board found fault with the communication of NUL's policies to the complainant, it concluded that the company was acting in accordance with its approved Natural Gas Sales Service Regulations in demanding a security deposit or letter of guarantee. The Board therefore considered that NUL was entitled to collect from the complainant all arrears relating to the supply of natural gas, including the related late payment penalties. In light of the lack of any written documentation or correspondence fully setting out its deposit requirements, the Board could not find any charges by NUL in relation to the deposit to be sustainable in this case, up until the date of the Board's order.

Further, in light of this complaint, the Board suggested that NUL might wish to consider adopting written service contracts, at least for commercial accounts, and providing documentation respecting security deposits, in the context of its general rate application.

4.30A **Northwestern Utilities Limited**
RE91009 / 910030 2090 14 2

B For approval of a summer gas cost recovery rate (GCRR) of $1.138 effective April 1, 1991, and to reconcile its 1990 summer period gas costs.

C In Interim Order C91015 dated March 31, 1991, the Board approved the 1991 summer GCRR of $1.138/GJ requested by NUL, stating that the calculations and forecasts used to derive the GCRR were reasonable. The approved GCRR was the same as the 1990 summer GCRR.

In Order C90010 dated March 12, 1990, the Board had postponed consideration of the 1989 reconciliation of summer season gas costs because the price of a "significant portion" of the gas supplied to NUL under long-term contracts subject to annual price redetermination was not then settled. In Order C91015, with prices for over 88% of the gas volumes supplied under such contracts settled for 1989 and 1990, the Board found that NUL's 1989 and 1990 summer season gas cost reconciliations were satisfactorily represented.

4.31A **Northwestern Utilities Limited**
RE91011 / 910032 2909 14 2

B For approval of a rate reduction rider of $0.162/GJ to adjust the winter period Gas Cost Recovery Rate, effective on all consumption on and after March 1, 1991. This reduction was a result of lower gas costs for both the short term/flexible

gas and export gas.

C Order E91013 dated March 1, 1991, approved NUL's application stating that it considered it beneficial for NUL's rates to reflect saving on the gas cost recovery component in a timely fashion.

4.32A **Northwestern Utilities Limited**
RE91047 / 910037 2230 14 2

B For an order approving the purposes of and authorizing the issue of 1,200,000 Series P Preferred Shares for $30,000,000 to Canadian Utilities Limited.

C Order E91064 dated August 15, 1991, approved the application.

4.33A **Northwestern Utilities Limited**
RE91050 / 910104 2090 14 2

B For approval of a Rate Reduction Rider "F" of $0.249/GJ to adjust the summer period Gas Cost Recovery Rate (GCRR), effective on all consumption on and after August 15, 1991 until October 31, 1991, inclusive. This reduction resulted from lower gas costs for both the short term/flexible gas and export gas.

C Order E91061 dated August 15, 1991, approved NUL's application stating that it was beneficial for NUL's rates to reflect savings on the gas cost recovery component in a timely fashion. The application also minimized the balance in NUL's DGA account. The creation of Rider "F" would expedite future changes to the GCRR when forecasts differ from actual rates.

4.34A **Northwestern Utilities Limited**
RE91065 / 910115 2090 14 2

B For a change in Rider "F" to reflect its winter gas cost recovery rate (GCRR), effective November 1, 1991, and for a change in its Rider "D" for collection of unaccounted for gas (UFG) costs, effective January 1, 1992.

C In Order C91045 dated October 23, 1991, the Board approved NUL's Rider "F" which set the 1991/92 winter GCRR of $1.264/GJ based on a cumulative deferred balance of $1,837,000 and forecast 1991/92 winter gas costs of $100,786,000. The Board also approved Rider "D" for UFG collections of 1.4%, based on NUL's three year rolling average UFG experience.

4.35A **Northwestern Utilities Limited**
RE91079 / 910127 2090 14 2

B For approval of a change in rates relating to the City of Camrose because of a change in the revenue tax rate.

C In process at year end.

4.36A **Northwestern Utilities Limited**
RE91088 / 910002 2060 14 3

B For approval of interim rates, tolls or charges in light of Phase 1 Decision E91044.

C In process at year end.

4.37A **Northwestern Utilities Limited**
RE91091 / 910035 2230 14 2

B For an order approving the purposes of and authorizing the issue of a 9.92% Debenture 1991 Series in the principal amount of $25,000,000 to Canadian Utilities Limited.

C Order E91105 dated December 19, 1991, approved the application.

Section 5: Utilities Not Offering Utility Services to the General Public

For an Order declaring that the provisions of Section 99 of the Public Utilities Board Act, and said Section 99, to the extent that it may be incorporated into the Gas Utilities Act by operation of Sections 50 and 51 of the Act, do not apply to the Applicants for the purposes of certain transactions.

5.1 **Inverness Petroleum Ltd. / 176065 Canada Limited**
RC91001 / 910003 3205 4651 2
Approved / C91001 dated January 14, 1991.

5.2 **Novalta Resources Inc. / a new subsidiary of Imperial Oil Limited (Newco)**
RC91002 / 910004 3205 4652 2
Approved / C91002 dated January 14, 1991.

5.3 **Esso Resources Canada Limited / Esso Resources Canada**
RC91004 / 910008 3205 4653 2
Approved / C91003 dated January 24, 1991.

5.4 **CanEuro Resources Ltd. / Polo Petroleum Ltd. / 424275 Alberta Ltd.**
RC91005 / 910009 3205 4654 2
Approved / C91004 dated January 24, 1991.

5.5 **Chauvco Oil & Gas Ltd. / 484360 Alberta Limited**
RC91008 / 910045 3205 4655 2
Approved / C91011 dated March 13, 1991.

5.6 **Dorset Exploration Ltd. / 489845 Alberta Limited**
RC91010 / 910082 3205 4656 2
Approved / C91016 dated April 22, 1991.

5.7 **Texaco Canada Petroleum Inc. / 2722054 Canada Limited / 2722062 Canada Limited / 2722071 Canada Limited / 2722101 Canada Limited / 2722119 Canada Limited**
RC91017 / 910095 3205 4657 2
Approved / C91022 dated June 21, 1991.

5.8 **Pembina Resources Limited / 489700 Alberta Ltd.**
RC91019 / 910096 3205 4658 2
Approved / C91029 dated June 25, 1991.

5.9 **424999 Alberta Ltd. / Peace Pipe Line Ltd.**
RC91023 / 910102 3205 4659 2
Approved / C91030 dated July 22, 1991.

5.10 **2727196 Canada Limited / 492715 Alberta Ltd.**
RC91025 / 910103 3205 4660 2
Approved / C91033 dated July 29, 1991.

5.11 **Paramount Resources Ltd. / Western D'Eldona Resources Limited / Grosmont Resources Ltd.**
RC91028 / 910113 3205 4661 2
Approved / C91035 dated August 30, 1991.

5.12 **424999 Alberta Ltd. / Peace Pipe Line Ltd.**
RC91030 / 910102 2170 4659 2
Approved / C91043 dated August 30, 1991.

5.13 **Pembina Energy Transmission Ltd.** on behalf of itself and **Pembina Corporation / Pembina Resources Limited / Pembina Oil Limited / Pembina Pipeline** (a partnership) / **Pemada Pipe Line Ltd. / Peace Pipe Line Ltd. / Pouce Coupe Pipe Line Ltd. / Plateau Pipe Line Ltd.**
RC91040 / 910126 3205 4663 2
Approved / C91048 dated October 25, 1991.

5.14 **Husky Oil Ltd. / Husky Oil Operations Ltd. / Husky Border Pipelines Ltd./ Canterra Exploration Ltd. / 147212 Canada Ltd.**
RC91049 / 910139 3205 4664 2
Approved / C91060 dated December 31, 1991.

Section 6A: Municipalities

Applications by municipalities, pursuant to the Municipal Government Act, for approval to enter into supply and special franchise agreements or renewals or alterations thereof with owners of utilities. Pursuant to the Act, new agreements may be for a period of 20 years while renewals may be for a period of up to 10 years. Where the municipality agrees to accept a percentage of the gross revenue of the franchise holder in lieu of taxing the special franchise and property of the holder used in the exercise of the franchise pursuant to the Municipal Taxation Act, the amount of such percentage is reflected.

Data reported in groups arranged alphabetically according to the name of the regulated

utility to which the application refers. Individual applications within each group are then arranged in order of registration number.

APPLICATION PARTICULARS

A APPLICANT REGISTRATION NUMBER / FILE NUMBER ITEM
B SUBJECT MATTER NUMBER
C DISPOSITION / REFERENCE

6.1 A **Town of St. Paul**
RE90056 / 900019 4005 105 2
B For approval to renew an electric power supply contract, to confer a special franchise and to renew a revenue tax agreement / Alberta Power Limited / based on an escalating percentage calculated on four block levels of gross revenue of the municipal franchise.
C Approved / E91025 dated April 10, 1991.

6.2 A **Village of Willingdon**
RE91003 / 910006 4005 315 2
B For approval to renew an electric power supply contract, to confer a special franchise and to renew a revenue tax agreement / Alberta Power Limited / based on an escalating percentage calculated on four block levels of gross revenue of the municipal franchise.
C Approved / E91026 dated April 10, 1991.

6.3 A **Town of Swan Hills**
RE91021 / 590005 4005 109 2
B For approval to renew an electric power supply contract, to confer a special franchise and to enter into a revenue tax agreement / Alberta Power Limited / at a rate of 5%.
C Approved / E91046 dated July 24, 1991.

6.4 A **Town of Fox Creek**
RE91022 / 570003 4005 55 2
B For approval to enter into an electric power supply contract, to confer a special franchise and to enter into a revenue tax agreement / Alberta Power Limited / based on an escalating percentage calculated on four block levels of gross revenue of the municipal franchise.
C In process at year end.

6.5 A **Village of Hairy Hill**
RE91023 / 360002 4005 231 2
B For approval to renew an electric power supply contract, to confer a special franchise and to enter into a revenue tax agreement / Alberta Power Limited / at a rate of 3%.
C Approved / E91068 dated August 30, 1991.

6.6 A **Village of Elnora**
RE91029 / 400003 4005 211 2
B For approval to renew an electric power supply contract, to confer a special franchise and to enter into a revenue tax agreement / Alberta Power Limited / based on an escalating percentage calculated on four block levels of gross revenue of the municipal franchise.
C In process at year end.

6.7 A **Village of Rosalind**
RE91037 / 470005 4005 281 2
B For approval to renew an electric power supply contract, to confer a special franchise, and to renew a revenue tax agreement / Alberta Power Limited / based on an escalating percentage calculated on four block levels of gross revenue of the municipal franchise.
C Approved / E91048 dated August 30, 1991.

6.8 A **Village of Wanham**
RE91038 / 410004 4005 801 2
B For approval to renew an electric power supply contract, to confer a special franchise, and to renew a revenue tax agreement / Alberta Power Limited / based on an escalating percentage calculated on four block levels of gross revenue of the municipal franchise.
C Approved / E91049 dated August 30, 1991.

6.9 A **Village of Halkirk**
RE91043 / 290004 4005 232 2
B For approval to renew an electric power supply contract, to confer a special franchise, and to renew a revenue tax agreement / Alberta Power Limited / based on an escalating percentage calculated on four block levels of gross revenue of the municipal franchise.
C In process at year end.

6.10A **City of Grande Prairie**
RE91046 / 270003 4005 952 2

B For approval to renew an electric power supply contract, to confer a special franchise and to renew a revenue tax agreement / Alberta Power Limited / at an initial rate of 5% until the end of 1993, 6% until the end of 1996 and 7% from January 1, 1997 onwards.

C In process at year end.

6.11A **Town of Coronation**
RE91060 / 280009 4005 42 2

B For approval to renew an electric power supply contract, to confer a special franchise, and to renew a revenue tax agreement / Alberta Power Limited / based on an escalating percentage calculated on four block levels of gross revenue of the municipal franchise.

C In process at year end.

6.12A **City of Drumheller**
RE91018 / 530003 4020 950 2

B For approval to renew its natural gas supply contract with, to confer a special franchise on, and to renew its revenue tax agreement with Big Country Gas Co-op Ltd., with respect to certain annexed lands.

C Decision E91041 dated June 20, 1991 approved the application. The Board found that the Co-op had an adequate supply of natural gas; was financially able to provide service; and had a good safety record. The Board did have some general concerns with respect to the provision of natural gas service within the municipality by two different distributors. In this instance it appeared that no safety problems had arisen, and no objections were filed by either the residents of the City or the other distributor serving within the municipality. The Board therefore concluded that it was reasonable and appropriate to approve the application.

6.13A **Village of Coutts**
RE87038 / 280008 4006 194 2

B For approval of the termination of a special franchise with Border Power Ltd.

C The application was withdrawn by the applicant, in light of the sale of Border Power to TransAlta Utilities Corporation.

6.14A **City of Lethbridge**
RC90037 / 900030 4007 099 2

B For approval to enter into a renewal of a natural gas supply contract, to confer a special franchise and to renew a revenue tax agreement / Canadian Western Natural Gas Company Limited / at a rate of 11.11%.

C Order C91007 dated April 30, 1991 approved the application, with written reasons to follow.

6.15A **City of Calgary**
RC91003 / 910007 4007 24 2

B For approval to enter into an alteration of its revenue tax agreement with Canadian Western Natural Gas Company Limited.

C Order C91009 dated April 30, 1991 approved the application, with written reasons to follow.

6.16A **Town of Innisfail**
RC91006 / 910013 4007 67 2

B For approval to enter into an alteration of its natural gas supply contract and special franchise agreement with Canadian Western Natural Gas Company Limited.

C Order C91008 dated April 30, 1991 approved the application with written reasons to follow.

6.17A **The Municipality of Crowsnest Pass**
RC91026 / 790002 4007 600 2

B For approval to amend its franchise agreement with Canadian Western Natural Gas Company Limited to include natural gas transportation customers.

C Approved / C91046 dated October 30, 1991.

6.18A **Village of Cowley**
RC91029 / 580002 4007 195 2

B For approval to renew a natural gas supply contract, to confer a special franchise, and to renew a revenue tax agreement / Canadian Western Natural Gas Company Limited / at a rate of 5.26%.

C Approved / C91026 dated June 26, 1991.

6.19A **Town of Banff**
RC91032 / 900147 4007 140 2

B For approval to enter into a natural gas supply contract with, to confer a special franchise and to

enter into a revenue tax agreement / Canadian Western Natural Gas Company Limited / at a rate of 5.26%.

C Approved / C91049 dated November 27, 1991.

6.20A **Town of Crossfield**
RC91037 / 510007 4007 138 2

B For approval to amend its franchise agreement with Canadian Western Natural Gas Company Limited to include natural gas transportation customers.

C Approved / C91054 dated November 27, 1991.

6.21A **Village of Linden**
RC91041 / 640009 4007 252 2

B For approval to renew a natural gas supply contract, to confer a special franchise and to renew a revenue tax agreement / Canadian Western Natural Gas Company Limited / at a rate of 5.26%.

C Approved / C91056 dated December 13, 1991.

6.22A **Town of Fort Macleod**
RC91043 / 310005 4007 52 2

B For approval to renew a natural gas supply contract, to confer a special franchise and to renew a revenue tax agreement / Canadian Western Natural Gas Company Limited / at a rate of 5.26%.

C Approved / C91057 dated December 13, 1991.

6.23A **Town of High Level**
RE90027 / E6.63.4

B For approval to renew a natural gas supply contract, to confer a special franchise and to enter into a revenue tax agreement / Centra Gas Alberta Inc. / at a rate of 6.1%.

C Approved / E91021 dated April 10, 1991.

6.24A **Town of Athabasca**
RE90081 / 900063 4015 22 2

B For approval to enter into an amendment of its special franchise agreement with Centra Gas Alberta Inc. to increase the franchise tax rate from 3% to 4%.

C Approved / E91020 dated April 10, 1991.

6.25A **City of Drumheller**
RE91044 / 530003 4015 950 2

B For approval to renew a natural gas supply contract, to confer a special franchise and to renew a revenue tax agreement / Centra Gas Alberta Inc. / at a rate of 6%.

C Approved / E91079 dated November 20, 1991.

6.26A **Town of St. Paul**
RE91050 / 490005 4015 105 2

B For approval to renew a natural gas supply contract, to confer a special franchise and to renew a revenue tax agreement / Centra Gas Alberta Inc. / at a rate of 6%.

C Approved / E91080 dated November 20, 1991.

6.27A **Town of Pincher Creek**
RE91080 / 560007 4015 87 2

B For approval to renew a natural gas supply contract, to confer a special franchise and to renew a revenue tax agreement / Centra Gas Alberta Inc. / at an initial rate of 3.1% until the end of 1993, 4.1% until the end of 1996 and 4.1% from January 1, 1997 onwards.

C In process at year end.

6.28A **County of Strathcona No. 20**
RE91084 / 510002 4020 422 2

B For approval to enter into a water supply contract and to confer a special franchise / CU Water Limited.

C In process at year end.

6.29A **Town of Ponoka**
RE90061 / 410002 4014 88 2

B For approval to renew a natural gas supply contract, to confer a special franchise and to renew a revenue tax agreement / Northwestern Utilities Limited / at a rate of 5.26%.

C Approved / E91042 dated June 26, 1991.

6.30A **Summer Village of Silver Beach**
RE90069 / 900051 4014 291 2
B For approval to renew a natural gas supply contract, to confer a special franchise and to renew a revenue tax agreement / Northwestern Utilities Limited / at a rate of 5.26%.
C Approved / E91009 dated March 7, 1991.

6.31A **Town of Bashaw**
RE90071 / 900055 4014 24 2
B For approval to renew a natural gas supply contract, to confer a special franchise, and to renew a revenue tax agreement / Northwestern Utilities Limited / at a rate of 5.25%.
C Approved / E91005 dated February 13, 1991.

6.32A **Town of Vermilion**
RE90093 / 900083 4014 118 2
B For approval to renew a natural gas supply contract, to confer a special franchise and to renew a revenue tax agreement / Northwestern Utilities Limited / at a rate of 5.26%.
C Approved / E91010 dated March 7, 1991.

6.33A **Town of Rimbey**
RE91017 / 550008 4014 94 2
B For approval to renew a natural gas supply contract, to confer a special franchise and to renew a revenue tax agreement / Northwestern Utilities Limited / at a rate of 5.26%.
C Approved / E91043 dated June 26, 1991.

6.34A **Village of Clive**
RE91064 / 610005 4014 190 2
B For approval to renew a natural gas supply contract, to confer a special franchise and to renew a revenue tax agreement / Northwestern Utilities Limited / at a rate of 5.25%.
C Approved / E91082 dated November 20, 1991.

6.35A **City of Camrose**
RE91078 / 410006 4014 949 2
B For approval to renew a natural gas supply contract, to confer a special franchise and to renew a revenue tax agreement / Northwestern Utilities Limited / at a rate of 8.11%.
C In process at year end.

6.36A **Village of Thorhild**
RC90035 / 900025 4006 299 2
B For approval to renew an electric power supply contract and to confer a special franchise / TransAlta Utilities Corporation.
C Approved / C91005 dated February 13, 1991.

6.37A **Town of Hardisty**
RC90036 / 900027 4006 62 2
B For approval to renew an electric power supply contract and to confer a special franchise / TransAlta Utilities Corporation.
C Approved / C91006 dated February 13, 1991.

6.38A **Village of Tilley**
RC90046 / 900038 4006 301 2
B For approval to renew an electric power supply contract and to confer a special franchise / TransAlta Utilities Corporation.
C Approved / C91021 dated May 8, 1991.

6.39A **Village of Holden**
RC91007 / 910044 4006 237 2
B For approval to renew an electric power supply contract and to confer a special franchise / TransAlta Utilities Corporation.
C Approved / C91027 dated June 26, 1991.

6.40A **Town of Westlock**
RC91011 / 280002 4006 122 2
B For approval to renew an electric power supply contract and to confer a special franchise / TransAlta Utilities Corporation.
C Approved / C91028 dated June 26, 1991.

6.41A **Village of Grassy Lake**
RC91013 / 470003 4006 229 2
B For approval to renew an electric power supply contract and to confer a special franchise / TransAlta Utilities Corporation.
C Approved / C91036 dated August 30, 1991.

6.42A **Town of Daysland**
RC91014 / 280005 4006 43 2
B For approval to renew an electric power supply contract and to confer a special franchise / TransAlta Utilities Corporation.

C Approved / C91037 dated August 30, 1991.

6.43A **Town of Black Diamond**
RC91015 / 290002 4006 27 2
B For approval to renew an electric power supply contract and to confer a special franchise / TransAlta Utilities Corporation.
C Approved / C91038 dated August 30, 1991.

6.44A **Village of Hay Lakes**
RC91016 / 440002 4006 233 2
B For approval to renew an electric power supply contract and to confer a special franchise / TransAlta Utilities Corporation.
C Approved / C91039 dated August 30, 1991.

6.45A **Village of Fort Assiniboine**
RC91018 / 480006 4006 218 2
B For approval to renew an electric power supply contract and to confer a special franchise / TransAlta Utilities Corporation.
C Approved / C91040 dated August 30, 1991.

6.46A **City of Spruce Grove**
RC91020 / 470006 4006 19 2
B For approval to renew an electric power supply contract and to confer a special franchise / TransAlta Utilities Corporation.
C Approved / C91041 dated August 30, 1991.

6.47A **Village of Coutts**
RC91021 / 280008 4006 194 2
B For approval to enter into an electric power supply contract and to confer a special franchise / TransAlta Utilities Corporation.
C Approved / C91031 dated July 26, 1991.

6.48A **Village of Glenwood**
RC91024 / 310002 4006 226 2
B For approval to renew an electric power supply contract and to confer a special franchise / TransAlta Utilities Corporation.
C In process at year end.

6.49A **Village of Cowley**
RC91029 / 400005 4006 195 2
B For approval to renew an electric power supply contract and to confer a special franchise / TransAlta Utilities Corporation.
C Approved / C91051 dated November 27, 1991.

6.50A **Town of Redwater**
RC91031 / 410005 4006 93 2
B For approval to renew an electric power supply contract and to confer a special franchise / TransAlta Utilities Corporation.
C Approved / C91052 dated November 27, 1991.

6.51A **Town of Turner Valley**
RC91033 / 310003 4006 129 2
B For approval to renew an electric power supply contract and to confer a special franchise / TransAlta Utilities Corporation.
C Approved / C91053 dated November 27, 1991.

6.52A **Town of Sedgewick**
RC91034 / 280010 4006 96 2
B For approval to renew an electric power supply contract and to confer a special franchise / TransAlta Utilities Corporation.
C In process at year end.

6.53A **Village of Hill Spring**
RC91036 / 440006 4006 235 2
B For approval to renew an electric power supply contract and to confer a special franchise / TransAlta Utilities Corporation.
C In process at year end.

6.54A **Town of Barrhead**
RC91039 / 320002 4006 23 2
B For approval to renew an electric power supply contract and to confer a special franchise / TransAlta Utilities Corporation.
C In process at year end.

6.55A **Town of Vulcan**
RC91042 / 310004 4006 120 2
B For approval to renew an electric power supply contract and to confer a special franchise /

TransAlta Utilities Corporation.

C In process at year end.

6.56A **Town of Carstairs**
RC91046 / 280011 4006 35 2

B For approval to renew an electric power supply contract and to confer a special franchise / TransAlta Utilities Corporation.

C In process at year end.

6.57A **Town of Beaumont**
RC91047 / 460004 4006 131 2

B For approval to renew an electric power supply contract and to confer a special franchise / TransAlta Utilities Corporation.

C In process at year end.

6.58A **M.D. of Provost on behalf of the Hamlet of Cadogan**
RC91048 / 280003 4006 459 2

B For approval to renew an electric power supply contract and to confer a special franchise / TransAlta Utilities Corporation.

C In process at year end.

6.59A **Village of Edberg**
RC91050 / 280012 4006 208 2

B For approval to renew an electric power supply contract and to confer a special franchise / TransAlta Utilities Corporation.

C In process at year end.

6.60A **Town of Stony Plain**
RE90043 / 490007 4020 104 2

B For approval to enter into a natural gas supply and special franchise agreement with West Parkland Gas Co-op Ltd. with respect to certain annexed lands.

C Decision E91086 dated November 20, 1991 approved the application. NUL, who serves the remainder of the municipality, contested the Board's jurisdiction to grant the application. However, the Board was not persuaded by NUL's argument that the Town was precluded from entering into a special franchise agreement with the Co-op by virtue of the provisions of section 287 of the Municipal Government Act, noting that there did not appear to be any inconsistency between the provisions of section 279 and section 287. Further, the Chief Officer pursuant to the Rural Gas Act had expressed his support for the application, indicating that he intended to alter the Co-op's franchise area approval to exclude the annexed lands therefrom upon the Board's approval of the special franchise agreement. The Board therefore concluded that the Town could proceed with its application pursuant to section 279.

With respect to the merits of the application, the Board determined that the Co-op was financially and otherwise able to provide service in the annexed areas; the Co-op had an adequate supply of natural gas; and had an excellent safety record. While the Board expressed some general concerns with respect to the provision of natural gas service by two different distributors within a municipality, it was apparent that the Town Council in this instance had weighed its options and had concluded that it would be in the public interest to grant a special franchise to the Co-op. The majority of the Board therefore concluded that it was reasonable and appropriate to approve the application. Member R.D.S. Ward dissented. In his dissent he raised concerns respecting safety, customer confusion and fair rates, pointing out that only NUL's rates were established by the Board. Further, he found that denial of the application would not cause any hardship to the Co-op. Indeed, he noted the option would remain open to the Town to consent to the Co-op serving within its boundaries pursuant to section 287 of the Municipal Government Act.

Section 6B:

Applications by municipalities, pursuant to the Municipal Government Act, for approval to enter into contracts or renewals thereof, providing for the supply of light, power, natural gas artificial gas or water to the municipality for the use of the municipal public utility.

Data reported in order of registration number.

6.61A **City of Red Deer**
RC90047 / 900084 4000 12 2
B For approval to renew an electric power supply contract / TransAlta Utilities Corporation.
C Approved / C91010 dated March 20, 1991.

6.62A **Village of Thorhild**
RE90095 / 900085 4000 299 2
B For approval to renew a natural gas supply contract / Pan Alberta Gas Ltd.
C Approved / E91014 dated March 7, 1991.

6.63A **Village of Forestburg**
RE91007 / 910019 4000 217 2
B For approval to enter into an alteration of a natural gas supply contract / Voyager Energy Inc.
C Approved / E91015 dated March 7, 1991.

6.64A **Town of Devon**
RE91014 / 910038 4000 44 2
B For approval to enter into an alteration (price of gas) of a natural gas supply contract / Esso Resources Canada Limited.
C Approved / E91018 dated March 20, 1991.

6.65A **Town of Tofield**
RE91083 / 910114 4000 112 3
B For approval to enter into a water supply contract / CU Water Limited.
C In process at year end.

Section 6C:

Applications by the Minister of Municipal Affairs, pursuant to the Improvement Districts Act and the Special Areas Act, for approval to enter into contracts with utilities undertaking to provide street lighting in a hamlet situated in an improvement district or special area, or with utilities to supply light, power, natural gas, water or a sewerage system to persons resident in the improvement district or special area or in any specified part or parts thereof.

The following applications were all for approval of street lighting agreements with Alberta Power Limited. They are arranged in order of registration number.

6.66A **Minister of Municipal Affairs for the Hamlet of Kirriemuir**
RE90072 / 550012 4025 553 2
B For approval to renew a street lighting agreement
C Approved / E91051 dated August 14, 1991.

6.67A **Minister of Municipal Affairs for the Hamlet of Sedalia**
RE90073 / 550009 4025 552 2
B For approval to renew a street lighting agreement
C Approved / E91052 dated August 14, 1991.

6.68A **Minister of Municipal Affairs for the Hamlet of Excel**
RE90074 / 520007 4025 554 2
B For approval to renew a street lighting agreement
C Approved / E91054 dated August 14, 1991.

6.69A **Minister of Municipal Affairs for the Hamlet of Benton**
RE90075 / 530008 4025 556 2
B For approval to renew a street lighting agreement
C Approved / E91055 dated August 14, 1991.

6.70A **Minister of Municipal Affairs for the Hamlet of Pollockville**
RE90076 / 560005 4025 557 2
B For approval to renew a street lighting agreement
C Approved / E91056 dated August 14, 1991.

6.71A **Minister of Municipal Affairs for the Hamlet of Bindloss**
RE90077 / 480004 4025 558 2
B For approval to renew a street lighting agreement
C Approved / E91057 dated August 14, 1991.

6.72A **Minister of Municipal Affairs for the Hamlet of New Brigden**
RE90078 / 550010 4025 562 2
B For approval to renew a street lighting agreement
C Approved / E91058 dated August 14, 1991.

6.73A **Minister of Municipal Affairs for the Hamlet of Chinook**
RE90079 / 440004 4025 188 2
B For approval to enter into a street lighting agreement
C Approved / E91050 dated August 14, 1991.

6.74A **Minister of Municipal Affairs for the Hamlet of Esther**
RE91004 / 550011 4025 563 2
B For approval to renew a street lighting agreement
C Approved / E91053 dated August 14, 1991.

6.75A **Minister of Municipal Affairs for the Hamlet of North Star**
RE91053 / 520005 4025 909 2
B For approval to renew a street lighting agreement
C Approved / E91087 dated December 13, 1991.

6.76A **Minister of Municipal Affairs for the Hamlet of Dixonville**
RE91054 / 480003 4025 521 2
B For approval to renew a street lighting agreement
C Approved / E91088 dated December 13, 1991.

6.77A **Minister of Municipal Affairs for the Hamlet of Notikewin**
RE91055 / 910108 4025 73 2
B For approval to enter into a street lighting agreement
C Approved / E91089 dated December 13, 1991.

6.78A **Minister of Municipal Affairs for the Hamlet of Deadwood**
RE91056 / 910109 4025 126 2
B For approval to enter into a street lighting agreement
C Approved / E91090 dated December 13, 1991.

6.79A **Minister of Municipal Affairs for the Hamlet of Carcajou**
RE91057 / 910110 4025 128 2
B For approval to enter into a street lighting agreement
C Approved / E91091 dated December 13, 1991.

6.80A **Minister of Municipal Affairs for the Community of Keg River**
RE91058 / 910111 4025 142 2
B For approval to enter into a street lighting agreement
C Approved / E91092 dated December 13, 1991.

6.81A **Minister of Municipal Affairs for the Hamlet of Peoria**
RE91068 / 540006 4025 906 2
B For approval to renew a street lighting agreement
C Approved / E91083 dated November 20, 1991.

6.82A **Minister of Municipal Affairs for the Hamlet of Tangent**
RE91069 / 500003 4025 907 2
B For approval to renew a street lighting agreement
C Approved / E91084 dated November 20, 1991.

6.83A **Minister of Municipal Affairs for the Hamlet of Watino**
RE91070 / 540007 4025 908 2
B For approval to renew a street lighting agreement
C Approved / E91085 dated November 20, 1991.

6.84A **Minister of Municipal Affairs for the Hamlet of Little Buffalo**
RE91071 / 910118 4025 963 2
B For approval to enter into a street lighting agreement
C Approved / E91075 dated November 20, 1991.

6.85A **Minister of Municipal Affairs for the Hamlet of Marie Reine**
RE91072 / 910119 4025 964 2
B For approval to enter into a street lighting agreement
C Approved / E91076 dated November 20, 1991.

6.86A **Minister of Municipal Affairs for the Hamlet of St. Isidore**
RE91073 / 910120 4025 965 2
B For approval to enter into a street lighting agreement
C Approved / E91077 dated November 20, 1991.

6.87A **Minister of Municipal Affairs for the Hamlet of Reno**
RE91074 / 620003 4025 890 2
B For approval to renew a street lighting agreement
C Approved / E91078 dated November 20, 1991.

Section 6D:

Complaints by users of public utilities, pursuant to Section 291 of the Municipal Government Act, respecting service charges, rates or tolls.

6.88A **Town of Sylvan Lake**
RE91062 / 910088 4200 108 3
B Complaint by Mr. Wilfred Zohner alleging improperly imposed water charges.
C In process at year end.

Section 6E:

Applications for approval or consent for actions other than those described in Sections 6A through 6D.

NIL

Section 7: Milk Pricing

Data reported in order of registration number.

7.1 A **Palm Dairies Inc. / Northern Alberta Dairy Pool Limited / Central Alberta Dairy Pool / Lucerne Foods Ltd.**
RE90[illegible] / RE90057 / E8.4.11-22 (P.D.) / 90002[illegible] 5410 4 2
B1 Application dated March 28, 1990 for approval for an increase in the wholesale and retail price of fluid milk of four cents per litre. The requested four cents increase was in addition to the one cent interim increase awarded in Interim Order E89109 dated December 7, 1989 which became effective December 15, 1989.
B2 Application dated August 29, 1990 by Lucerne Foods Ltd. (Lucerne) for the Board to accept financial information on a confidential basis.
B3 Application dated October 9, 1990 by Alpha Milk Company (Alpha) for the Board to approve prices for four litre bulk and one litre containers of 18% cream.
C1 In Decision E91008 dated February 19, 1991, the Board approved a one cent per litre increase in the wholesale and retail prices of fluid milk, cream and other fluid milk products effective March 1, 1991. This increase was in addition to the one cent per litre interim increase awarded in Order E89109 dated December 7, 1989, effective December 15, 1989 and the one cent per litre interim increase awarded in Order E90078 dated November 23, 1990 effective December 1, 1990. The Board considered that the total increase of three cents per litre would result in a 1990 annualized after tax return of 1.49% on sales or 23.76% on deemed equity. For 1991, on a non-annualized basis, a return of 1.31% on sales or 21.31% on deemed equity would result

for the Applicant Processors/Distributors.

(a) Sales Volumes

Sales volumes were increased approximately 1% over actual 1989 volumes for forecast 1990 to 213,500,000 litres. This increase was 4,058,709 litres or 1.94% higher than the 1990 Applicant Processors/Distributors' forecast. The Board increased forecast 1990 sales by a further 1% to arrive at forecast 1991 sales of 215,600,000 litres.

(b) Sales Revenue and Cost of Raw Milk and Ingredients

The Board found that it was appropriate to annualize both sales revenue and cost of raw milk and ingredients and to recognize increases in producer, wholesale and retail prices in order to determine a proper price for fluid milk. The Board also found it appropriate to adjust the increases in the producer price by the ratio of 1989 litres converted by Schedule 1 of the Dairy Control Board Regulations over 1989 litres sold. Converted litres are the basis on which a milk processor incurs raw milk expense.

(c) Common Costs

The Board accepted each of the common cost allocation methodologies for the purposes of this Decision except for the interest allocation method. Interest allocation was covered in the "Interest Expense" section.

(d) Forecast Expenses

All forecast expenses with the exception of raw milk and ingredients, containers, interest expense and income tax were found to be reasonable. The expense increases except for depreciation, advertising and those items noted above was a compounded increase of 3.16% per annum for the period of 1987 to 1990 inclusive. Containers expense was adjusted to reflect increased forecast sales volumes for 1990. The forecast level for 1991 was derived by increasing expenses with the exception of those items noted above by 4%. For 1991 containers expense on a cents per litre basis was increased 4% and adjusted for increased forecast volumes.

(e) Investment in Fluid Milk Operations

The Board calculated year end 1990 net plant investment in fluid milk operations to be $20,855,849. The Board constructed a proxy lead/lag schedule which indicated there was no need for any fluid milk working capital or for any interest expense to support fluid milk working capital. The lead/lag schedule provides for the use of a one month of the annual containers and supplies and a three-day inventory of raw milk and ingredients to recognize inventory associated with raw milk, pasteurized and refrigerated storage of fluid milk.

(f) Interest Expense

The Board considered a 40% debt:60% equity ratio would be a reasonable normalized capital structure. The Board estimated the embedded interest rate for 1988 to be 11.53% and for the purpose of the Decision considered 12% to be an appropriate cost of debt for 1990. The Board allowed a forecast 1990 and forecast 1991 interest expense of $1,001,081. The Board adjusted the accounting policies to reflect the Board's findings concerning the calculation of fluid milk interest expense.

(g) Income Tax Expense

The Board reaffirmed its position on income tax expense contained in Decision E88021 dated February 23, 1988. Income tax is to be calculated on a stand alone basis for the Applicant Processor /Distributor that is a taxable corporation. The Board calculated income tax expense in reference only to the recovery of costs that relate to fluid milk operations and used the normalized income tax method, assuming no permanent or timing differences between income for accounting purposes and income for tax purposes. For the purposes of the Decision, the Board used an effective income tax rate of 17.57% for 1990 and 9.76% for 1991 to reflect the aggregate volumes and revenues attributable to the taxable entity within the Applicant Processors/Distributors.

(h) Return Requirements

The Board considered that a 2½% return on fluid milk sales, which provides a 62% return on actual equity investment or a 40% return on deemed equity investment to be unreasonably high. The Board noted that if a 2½% return on fluid milk sales were awarded, the level of net income would provide a 12.02% return on equity for total equity investment in Board and non-Board regulated activities. The Board found a required return on sales of 1% based on deemed equity to be appropriate as it provides for a 15% return on deemed equity. The Board noted that the average of the non-annualized results for 1990 and

1991 would produce an appropriate return on sales (ie. 1%) and an appropriate rate of return on deemed equity investment (ie. 15%) for the Applicant Processors / Distributors. The Board constructed proxy industry results and found that by providing a return on sales for the Applicant Processors/Distributors on annualized 1990 of 1.49% and non-annualized 1991 of 1.31%, it was allowing an industry return on sales of 2.51% and 2.35% for those years respectively.

C2 The Board denied Lucerne's application to file on a confidential basis and noted that this finding was consistent with Decision E90023 dated March 2, 1990 concerning the issue of confidentiality respecting regulation of fluid milk operations. The Board expected that the next pricing application from Alberta processors/distributors would incorporate the financial results of Lucerne's fluid milk processing and distribution.

C3 The Board accepted the pricing structure for 18% cream as proposed by Palm Dairies Inc. The Board noted the last correspondence from Alpha and correspondence from Northern Alberta Dairy Pool supported Palm's pricing structure and considered the price to be in line with Board pricing structures.

7.2 A **Milk Producers as per report from the Department of Agriculture, Production Economics Branch**
RE91013 / 910034 5400 4444 2

B The Board proceeding on its own motion pursuant to section 12 of the Dairy Board Act to increase the minimum producer price of Class 1 fluid milk by $0.98 per hectolitre and the minimum wholesale and minimum retail prices by 1 cent per litre, effective March 15, 1991, consequent upon an increase in the producer price formula as monitored by the Department of Agriculture.

C By Order E91012 dated March 1, 1991, the Board approved the increases in the minimum prices, effective March 15, 1991.

7.3 A **The fluid milk wholesalers and retailers**
RE91020 / 910098 5411 4447 2

B The Board proceeding on its own motion to rescind minimum retail prices on fluid milk products sold or distributed in the Province of Alberta.

C By Order E91037 dated July 2, 1991, the Board rescinded minimum retail prices for fluid milk products sold or distributed in the province of Alberta, effective June 27, 1991. This action was taken pursuant to Order in Council 424/91 dated June 27, 1991, which amended the regulations pertaining to the Dairy Control Board Act. The effect of this amendment was to remove from the definition of "milk" any milk product when sold by retail sale, thereby ending the Board's jurisdiction to set minimum retail prices.

7.4 A **Central Alberta Dairy Pool / Holgerson Dairies Inc. / Lucerne Foods Ltd. / Kappler Dairies Ltd. / Northern Alberta Dairy Pool / Palm Dairies Inc. / and those wholesalers/ retailers that sell fluid milk, cream and fluid milk products**
RE91025 / 910012 5411 4447 2

B Interim application dated May 23, 1991 from the Alberta Dairy Control Board requesting that wholesale and retail minimum prices be set at the Board's earliest convenience for the following fluid milk products packaged in four litre plastic jugs: homogenized milk, 2% partly skimmed milk, 1% partly skimmed milk, skim milk and 2% chocolate milk.

C1 By Interim Order E91034, dated May 24, 1991, the majority of the division assigned by the Board to this Application fixed an interim four cent differential for a four litre rigid plastic jug over a four litre pouch pak effective May 31, 1991. In arriving at its decision the majority examined the price recommendations made by Holgerson Dairies Inc. (Holgerson) and Central Alberta Dairy Pool, Palm Dairies Inc. and Northern Alberta Dairy Pool Limited (the P/D). Holgerson recommended prices for the four litre plastic jug be set equal to those set for four litre pouch paks. The P/D submitted that the New Brunswick Farm Products Marketing Commission approved a differential of eighteen cents between the minimum wholesale prices for four litre jugs and four litre pouches. The P/D also noted that the current Dairyland list price for the Vancouver area of 2% partly skimmed milk indicated an eight cent differential. The P/D recommended the four litre jug be twelve cents higher than the corresponding sized pouch pak. Of the twelve cents, five cents was for freight related to the importation of

jugs into Alberta. The majority considered that if there were a demand for jugs, then the manufacturing capacity would appear in Alberta rather quickly. Consequently, the majority regarded the range of price differential to be between zero and seven cents (12¢ - 5¢). The majority considered it unreasonable to grant the full differential of twelve cents on the basis of untested costs or to grant no price differential in the face of evidence from the P/D as to their costs and information from out of Alberta that differentials have been approved in other jurisdictions.

C2 Member N. W. MacDonald dissented, stating that he was not persuaded that it was in the public interest to prescribe different prices for milk products that are packaged in four litre plastic jugs compared with milk products packaged in four litre polyethylene pouch containers. Member MacDonald noted there were no price differentials existing for milk products packaged in different types of containers for any package size prior to the issuance of this Order. Further, the limited cost information that had been provided could not be accepted at face value because parties to this application had not had the opportunity to comment on the position or cost information submitted by other parties. To implement a price differential, by type of container, would be a significant departure from past Board practice and should not be implemented, even on an interim basis, without testing in a public hearing. Member MacDonald stated that in the interim, he would have prescribed the same prices for milk products packaged in a four litre jug as had currently been prescribed by the Board for four litres of milk packaged in polyethylene pouch containers. Further, since the Board prescribes minimum prices, any processor/distributor would be free to establish its own price differential if it considered that its costs warranted a differential and/or that the market would support such a differential. Member MacDonald noted that the price of four litre plastic jugs as prescribed by the majority in the Order was three cents (3¢) more than two times the prescribed price of the two litre package size (which included two litre plastic jugs), an incongruous result. The price that he would have prescribed for four litre plastic pouch sizes would be one cent (1¢) less than two times the Board approved minimum price for two litre package sizes, a congruous result.

7.5 A **The Northern Alberta Dairy Pool**
RE91039 / 910084 5410 4445 2

B The Board proceeding on an application by the NADP to set a minimum wholesale price for 2% partly skimmed milk to be sold in 10 ml cups (creamers), in bags of 160 units.

C By Order E91045 dated July 3, 1991, the Board set a minimum wholesale price of $4.29 per bag of 160 units. NADP had requested a price of $5.29 per 160 unit bag. After reviewing cost and gross margin information provided by NADP, the Board decided to reduce the proposed minimum wholesale price so that the gross margin on the 2% creamers would be in line with that on the 10% creamers.

Section 8: Other Matters

Data reported in order of registration number.

8.1 A **Occidental Petroleum Ltd.**
RE89091 / 890007 2510 1028 2

B Application by Clyde R. Schwartz to fix and determine costs or the method for ascertaining costs incidental to gathering, treating or processing gas on designated lands.

C Application withdrawn by the applicant, as a settlement was reached between the parties.

8.2 A **North Canadian Oils Limited**
(formerly Bankeno Resources Limited) RE89108 / 890007 2510 1027 2

B Application by Hydra Resources Ltd. to fix and determine costs or the method for ascertaining costs incidental to gathering, treating or processing gas on designated lands.

C In process at year end.

8.3 A **R.W. Berry, Duhamel Resources Ltd. and Choya Petroleum Ltd.**
RE90025 / E4.4636.88-1

B Appeal from a decision of the Alberta Petroleum Marketing Commission (APMC) with respect to the Alberta Cost of Service Determination for TransCanada Pipelines Limited for the period of February 1983 to April 1987.

C In Decision C91034 dated August 30, 1991, the Board dismissed the appeal. R.W. Berry, Duhamel Resources Ltd. and Choya Petroleum Ltd. (the Producers) owned a beneficial interest in TransCanada Gas Contract #02181. In 1987 the Producers sold their interest in the properties under the contract. It was discovered that the contract had initially been placed in Category B1D2 of the TCPL multi-tiered classification system although it did not attract take-or-pay financing as part of the Top Gas Program. A change to category D1D2 was requested and granted by the APMC effective June, 1987. The Producers requested a retroactive classification for contract #02181 to D1D2 from February, 1983 to April, 1987. The APMC denied the application on the grounds that it has no jurisdiction to grant the relief requested and that the parties did not have standing, as the statement of objection had not been filed within the time prescribed. The Board stated that, although it may have broad powers as an appellate tribunal, it is still a creature of statute and derives its powers to act from statutes. An initial statement of objection filed within 60 days of the APMC's decision as prescribed in the regulations is necessary to invoke the jurisdiction of the Board. In this case, no application to the APMC respecting the categorization of the contract in which the Producers had a beneficial interest was filed until 1987. Consequently, the Board held that it did not have jurisdiction to consider the application.

8.4 A **Westcoast Energy Inc.**
RE91063 / E4.4662.88-1

B Appeal from a decision of the Alberta Petroleum Marketing Commission with respect to the Alberta Cost of Service Determination for Husky Oil Operations Ltd. and other Savanna Creek Producers for the period of February, 1980 to December, 1981.

C In process at year end.

8.5 A **NOVA Corporation of Alberta**
RE91094 / 91088 5000 536 3

B Complaint by the Alberta Gas Producer Group alleging that NOVA's rates, tolls or charges to be charged to customers effective January 1, 1992 are not just and reasonable.

C In process at year end.

8.6 A **NOVA Corporation of Alberta**
RE91095 / 91088 5000 536 4

B Complaint by the Independent Petroleum Association alleging that NOVA's rates, tolls or charges to be charged to customers effective January 1, 1992 are not just and reasonable.

C In process at year end.

8.7 A **NOVA Corporation of Alberta**
RE91096 / 91088 5000 536

B Complaint by the Canadian Petroleum Association alleging that NOVA's rates, tolls or charges to be charged to customers effective January 1, 1992 are not just and reasonable.

C In process at year end.

Litigation Proceedings

Appeals of Board Orders and Decisions. There were no litigation matters to report in 1991.

Legislative Authorities

Alberta Statutes which explicitly govern the Public Utilities Board are listed alphabetically.

1. Administrative Procedures Act, R.S.A. 1980, c. A-2
2. Alberta Resources Railway Corporation Act, R.S.A. 1980, c. A-36
3. City Transportation Act, R.S.A. 1980, c. C-10
4. Clean Air Act, R.S.A. 1980, c. C-12
5. Clean Water Act, R.S.A. 1980, c. C-13
6. County Act, R.S.A. 1980, c. C-27
7. Crowsnest Pass Municipal Unification Act, R.S.A. 1980, c. C-39
8. Dairy Board Act. R.S.A. 1980, c. D-1
9. Department of the Environment Act, R.S.A. 1980, c. D-19
10. Electric Energy Marketing Act. S.A. 1981, c. E-4.1
11. Electric Power and Pipe Line Assessment Act, R.S.A. 1980, c. E-5
12. Gas Utilities Act, R.S.A. 1980, c. G-4
13. Hydro and Electric Energy Act, R.S.A. 1980, c. H-13
14. Improvement Districts Act, R.S.A. 1980, c. I-1
15. Licensing of Trades & Businesses Act, R.S.A. 1980, c. L-13
16. Municipal Government Act, R.S.A. 1980, c. M-26
17. Municipal Taxation Act, R.S.A. 1980, c. M-31
18. Natural Gas Marketing Act, S.A. 1986, c. N-2.8
19. Natural Gas Price Administration Act, R.S.A. 1980, c. N-3
20. Natural Gas Pricing Agreement Act, R.S.A. 1980, c. N-4
21. Natural Gas Rebates Act, R.S.A. 1980, c. N-5
22. NOVA Corporation of Alberta Act, R.S.A. 1980, c. N-12
23. Oil and Gas Conservation Act, R.S.A. 1980, c. 0-5
24. Petroleum Marketing Act, R.S.A. 1980, c. P-5

25. Public Utilities Board Act, R.S.A. 1980, c. P-37
26. Railway Act, R.S.A. 1980, c. R-4
27. Regional Municipal Services Act, S.A. 1981, c. R-9.1
28. Rural Electrification Long Term Financing Act, R.S.A. 1980, c. R-17
29. Rural Electrification Revolving Fund Act, R.S.A. 1980, c. R-18
30. Rural Gas Act, R.S.A. 1980, c. R-19
31. Small Power Research and Development Act, R.S.A. 1980, c. S-13.75
32. Telecommunications Act, R.S.A. 1980, c. T-3.5
33. Water, Gas and Electric Companies Act, R.S.A. 1980, c. W-4
34. Water Resources Act, R.S.A. 1980, c. W-5

Utilities Fully Regulated by The Board*

Electric Utilities
AEC Power Ltd.
Alberta Power Limited
TransAlta Utilities Corporation

Water Utilities
Acheson Park Water Corporation
CU Water Limited

Natural Gas Utilities
Bonnyville Gas Company Limited
Canadian Western Natural Gas Company Limited
Centra Gas Alberta Inc.
Elk Point Gas, Ltd.
Northwestern Utilities Limited
Orr Mineral Developments Ltd.

* Denotes those companies providing traditional utility services directly to end users, and whose operations are subject to the full jurisdiction of the Board.

Appendix 5

The following tables outline monthly bills for an average residential customer for the period from January 1, 1980 to January 1, 1992. The calculations are based upon an assumed annual consumption of 6000 kWh for electricity and 165 GJ for natural gas. The bills have been calculated including the franchise tax, where applicable, but excluding income tax rebates and GST.

1. Electric Utilities

ALBERTA POWER LIMITED

RATES EFFECTIVE	DECISION/ ORDER NO.	AVERAGE MONTHLY BILL	PERCENTAGE OVER 1980	INCREASE OVER PREVIOUS
Jan 1/80	E79170	$27.53	-	-
Jan 1/81	E80231	$32.29	17.29%	17.29%
Jan 1/82	E81179	$37.51	36.25%	16.17%
Jan 1/83	E82211	$33.69	22.38%	-10.18%
Jan 1/84	Filing 84-2	$36.75	33.49%	9.08%
Jan 1/85	Filing 84-1	$36.86	33.89%	0.30%
Jan 1/86	Filing 85-5	$35.29	28.19%	-4.26%
Jan 1/87	E86072	$36.71	33.35%	4.02%
Jan 1/88	E87132	$43.51	58.04%	18.52%
Jan 1/89	E88016	$45.66	65.86%	4.95%
Jan 1/90	E89011	$42.75	55.29%	-6.38%
Jan 1/91	E90051	$45.74	66.16%	7.00%
Jan 1/92	E91035	$49.39	79.40%	7.97%

TRANSALTA UTILITIES CORPORATION

RATES EFFECTIVE	DECISION/ ORDER NO.	AVERAGE MONTHLY BILL	PERCENTAGE OVER 1980	INCREASE OVER PREVIOUS
Jan 1/80	E79037	$23.59	-	-
Jan 1/81	E80009	$25.09	6.36%	6.36%
Jan 1/82	E81174	$29.00	22.96%	15.61%
Jan 1/83	E83001	$34.04	44.33%	17.38%
Jan 1/84	E83150	$39.21	66.23%	15.18%
Jan 1/85	E84067	$38.25	62.18%	-2.44%
Jan 1/86	E85006	$38.93	65.06%	1.78%
Jan 1/87	E86005	$40.65	72.36%	4.42%
Jan 1/88	E87125	$40.89	73.39%	0.60%
Jan 1/89	E86051*	$40.65	72.36%	-0.60%
Jan 1/90	E86051	$40.65	72.36%	0.00%
Jan 1/91	E90097	$40.90	73.41%	0.61%
Jan 1/92	E92006	$47.82	102.74%	16.91%

* Reflects end of Riders set in previous Orders

2. Natural Gas Utilities

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED

RATES EFFECTIVE	DECISION/ ORDER NO.	AVERAGE MONTHLY BILL	PERCENTAGE OVER 1980	INCREASE OVER PREVIOUS
Jan 1/80	E78103	$21.93	-	-
Jan 1/81	E80391	$34.07	55.36%	55.36%
Jan 1/82	E81249	$39.91	81.99%	17.14%
Jan 1/83	E82204	$55.07	151.17%	38.01%
Jan 1/84	E83140	$51.18	133.40%	-7.07%
Jan 1/85	E84047	$49.39	125.25%	-3.49%
Jan 1/86	C85248	$52.04	137.33%	5.36%
Jan 1/87	C86033	$51.95	136.93%	-0.17%
Jan 1/88	C87118	$49.83	127.24%	-4.09%
Jan 1/89	E88078	$48.51	121.24%	-2.64%
Jan 1/90	E89106	$47.74	117.71%	-1.60%
Jan 1/91	C90043	$47.25	115.47%	-1.03%
Jan 1/92	C91044	$48.88	122.90%	3.45%

CENTRA GAS ALBERTA INC.

RATES EFFECTIVE	DECISION/ ORDER NO.	AVERAGE MONTHLY BILL	PERCENTAGE OVER 1980	INCREASE OVER PREVIOUS
Jan 1/80	E79068	$24.51	-	-
Jan 1/81	E80197	$34.75	41.78%	41.78%
Jan 1/82	E81210	$36.45	48.73%	4.90%
Jan 1/83	E82199	$48.53	98.00%	33.13%
Jan 1/84	E83151	$51.58	110.47%	6.30%
Jan 1/85	E84130	$53.02	116.32%	2.78%
Jan 1/86	E85145	$51.84	111.52%	-2.22%
Jan 1/87	E86084	$52.47	114.07%	1.21%
Jan 1/88	E87081	$50.64	106.63%	-3.48%
Jan 1/89	E87081*	$49.86	103.44%	-1.54%
Jan 1/90	E89045	$49.86	103.44%	0.00%
Jan 1/91	E89045	$49.86	103.44%	0.00%
Jan 1/92	E92003	$49.73	102.92%	-0.26%

* The decrease reflected in the average monthly bill indicates the end of a deficiency rider.

NORTHWESTERN UTILITIES LIMITED

RATES EFFECTIVE	DECISION/ ORDER NO.	AVERAGE MONTHLY BILL	PERCENTAGE OVER 1980	INCREASE OVER PREVIOUS
Jan 1/80	E78029	$21.05	-	-
Jan 1/81	E80166	$36.21	72.00%	72.00%
Jan 1/82	E81209	$38.91	84.84%	7.46%
Jan 1/83	E82201	$52.03	147.18%	33.73%
Jan 1/84	E83117	$47.14	123.95%	-9.40%
Jan 1/85	E84141	$50.35	139.19%	6.81%
Jan 1/86	E85071	$48.85	132.08%	-2.97%
Jan 1/87	E86085	$46.41	120.47%	-5.00%
Jan 1/88	E87117	$43.84	108.26%	-5.54%
Jan 1/89	E88079	$44.78	112.75%	2.15%
Jan 1/90	E89098	$47.35	124.96%	5.74%
Jan 1/91	C90042	$47.43	125.32%	0.16%
Jan 1/92	E92002	$48.12	128.60%	1.46%